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COGENERATION AT NAVY BASES, NAVY ENERGY GUIDANCE STUDY.(U)

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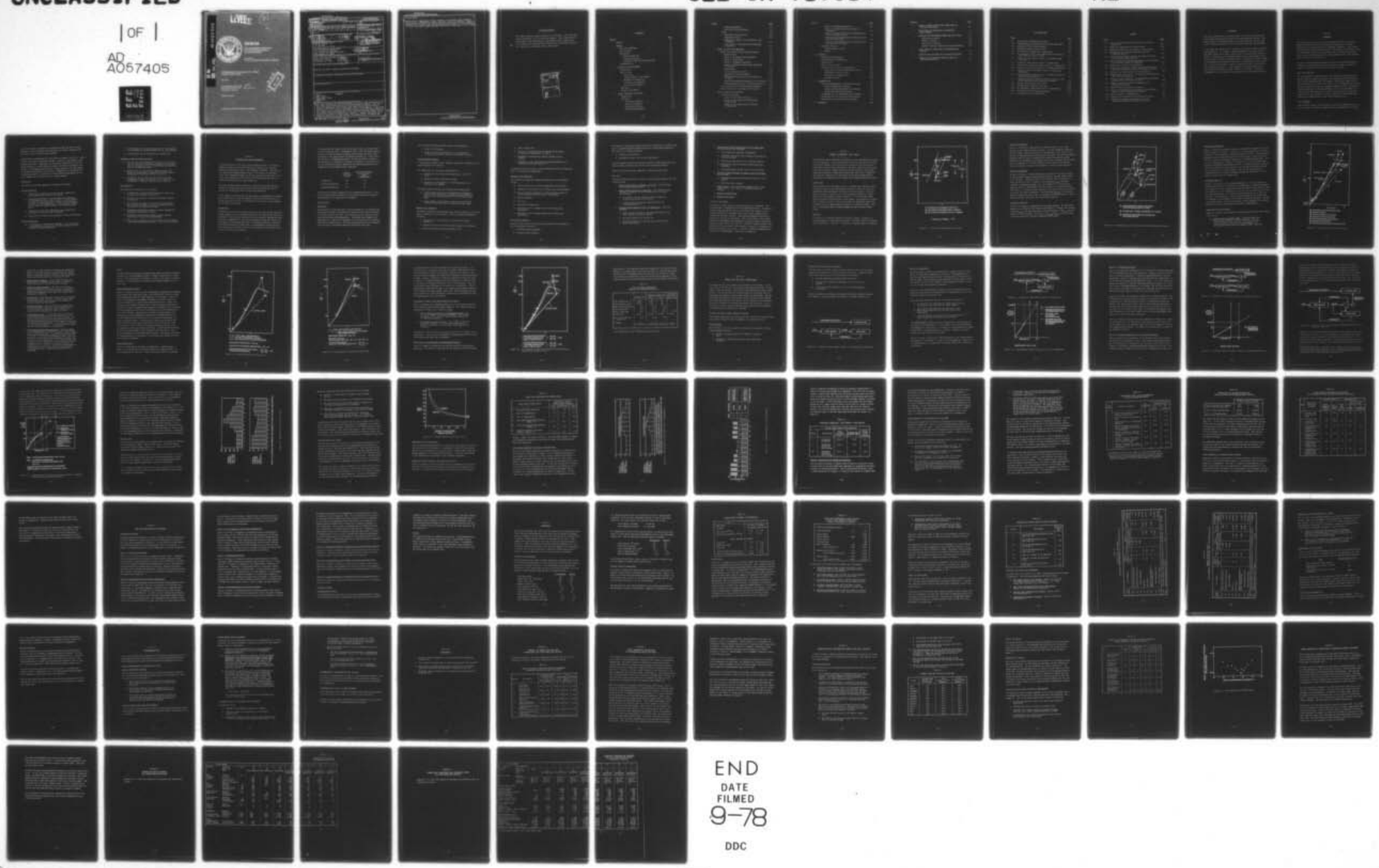

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CIVIL ENGINEERING LABORATORY
Naval Construction Battalion Center
Port Hueneme, California

Sponsored by
NAVAL FACILITIES ENGINEERING COMMAND

COGENERATION AT NAVY BASES, NAVY ENERGY GUIDANCE STUDY, PHASE I

May 1978

An Investigation Conducted by
BECHTEL NATIONAL, INC.
San Francisco, California

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This report analyzes the cost effectiveness of electric power generation at two Navy bases using existing boilers and turbine-generator systems. This study focused on cogeneration which occurs when steam from the power generation turbine can be used to satisfy heating and process steam demands. It was found that cogeneration is the most cost effective means of electric power generation. In contrast, condensing generation is less efficient than power supply from a public utility, and it is usually more expensive. However, occasional use of condensing generation for peak shaving is warranted because it reduces the

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ABSTRACT

This report analyzes the cost effectiveness of electric power generation at Navy bases using existing boilers and turbine-generator systems. This study focused on cogeneration which occurs when steam from the power generation turbine can be used to satisfy heating and process steam demands.

It was found that cogeneration is the most cost effective means of electric power generation. In contrast, condensing generation is less efficient than power supply from a public utility, and it is usually more expensive. However, occasional use of condensing generation for peak shaving is warranted because it reduces the demand charge. Application of these findings at Philadelphia Naval Shipyard could save up to $800,000 per year in fuel plus electricity purchases. Capital, operating and life cycle costs for new facilities show that it is not economical to install new electric power generation facilities at Navy bases if oil is used. A change is recommended in the procedures for preparing Utility Cost Analysis Reports.

Section 1

SUMMARY

The work described in this report was performed as Phase I of Contract N68305-77-C-0003 with the Civil Engineering Laboratory at the Naval Construction Battalion Center at Port Hueneme, California. The title of the contract was "Energy Guidance Study." The purpose of the Phase I effort was to determine whether it is cost effective for the Navy to continue using existing oil-fired boiler and turbine-generator units for continuous on-base electric power generation.

The study involved general parametric analysis and conceptual designs of systems for on-base generation, and also specific energy use and cost studies for *Philadelphia and Charleston Naval Shipyards.*

BASIS FOR COMPARISON

The installations considered required both electricity and heating and process steam for normal operations. The heating and process steam load could reach a maximum of 500 x 10^6 Btu/hr. The electric load could be satisfied either by purchase of all power, or by a combination of purchase and on-base generation with a 20 megawatt generation plant. The steam to loads was nominally at 100 psig saturated. Fuel oil was assumed to cost 3.00 $/$10^6$ Btu when burned in 87 percent efficient boilers. Purchased electricity prices followed the current schedule for Philadelphia Naval Shipyard and ranged between 25 and 30 mills/kilowatt-hour.

WORK PERFORMED

Work under the contract was performed in four areas, general steam cycle and efficiency calculations, energy use and cost comparisons of typical

and actual systems, preparation of conceptual designs and lists of major equipment of system variants, and computation of capital, operating, and life-cycle costs of variants being compared.

Cogeneration was highlighted as a key concept throughout the effort. Cogeneration occurs when steam passes through a turbine and then passes to the heating steam load. Cogeneration is attractive, because most of the fuel energy required to convert water to steam in the boiler is charged to production of the heating steam, and only a small portion of the fuel energy is charged to generation of electricity. Cogeneration is contrasted with condensing generation, in which the turbine exhaust steam emerges at too low a temperature to be useful for any heating purpose.

CONCLUSIONS

The results of the study support the following conclusions:

General Energy Use

- Cogeneration is always attractive from the standpoint of energy conservation and fuel cost savings.
- Condensing generation is less efficient than generation of purchased power from a public utility. It will usually cost more than purchased power. However, some condensing generation for peak shaving may be cost effective, because it can reduce the "demand" charge in the purchased power-price.
- Turbines with high inlet temperatures and pressures are preferable to those with lower conditions.
- High boiler efficiencies are preferable to lower efficiencies.

Shipyard Operations

- At Philadelphia, approximately $800,000 a year can be saved by switching to a strategy that maximizes cogeneration and minimizes condensing generation.

- At Philadelphia, continuous on-base electric power generation following the revised strategy will be cost effective.

- At Charleston, current operations are satisfactory.

Economics of New Oil-Fired Facilities

- New oil-fired power generation facilities are not attractive on a life cycle cost basis, compared to the alternative of purchasing all power and generating heating steam only in low pressure boilers.

- Capital costs of a new facility generating 500 x 10^6 Btu/hr of heating steam in low pressure boilers would be \$3,600,000, or \$7,200 per 10^6 Btu of capacity.

- Incremental capital costs for facilities to generate 20 megawatts of power in addition to the steam would be \$13,600,000, or \$680 per kilowatt-hour of capacity.

RECOMMENDATIONS

The following recommendations are provided:

- A cogeneration strategy should be adopted at bases with existing power generation facilities.

- All flows from turbines to heating steam headers should be monitored.

- The reporting procedure of the Utilities Cost Analysis Report should be changed to include a cogeneration fuel cost entry in the electricity column.

- Philadelphia Naval Shipyard should consider adopting the recommended cogeneration strategy.

- Philadelphia Naval Shipyard should promptly complete reactivation of their water demineralizer.

- Electric power generation facilities should not be included in new steam generation facilities, if oil is to be the fuel.

Section 2

INTRODUCTION AND BACKGROUND

The work described in this report was performed as Phase I of Contract N68305-77-C-0003 with the Civil Engineering Laboratory at the Naval Construction Battalion Center at Port Hueneme, California. The title of the contract was "Energy Guidance Study." The purpose of the Phase I effort was to determine whether it is cost effective for the Navy to continue using existing oil-fired boiler and turbine-generator units for continuous on-base electric power generation.

The study involved general parametric analysis and conceptual designs of systems for on-base generation, and also specific energy use and cost studies for Philadelphia and Charleston Naval Shipyards.

In the balance of this section, the key concept of cogeneration is defined, the contract scope of work is presented, the work plan followed in conducting the contract effort is discussed, and an outline of the remainder of the report is provided.

COGENERATION

A distinction that was used from the outset in the study was the difference between cogeneration and condensing generation in a medium sized industrial installation that requires electricity and also steam for heating and plant processes. Cogeneration occurs when steam passes through the turbine and then passes to the heating steam load. Condensing generation occurs when steam passes through the turbine into a low temperature vacuum condenser. The residual heat the steam contains is not suitable for any purpose, and it must be extracted and rejected.

In cogeneration the energy in the turbine exit steam can perform useful service as heating steam. Consequently, most of the fuel energy input to the boiler should be charged to making heating steam, and only a small increment of fuel energy should be charged to generation of electricity. By contrast, in condensing-generation, all the fuel energy required in the generation of steam must be charged to generation of the electricity. The cost difference between cogeneration and condensing generation are suggested by the following typical comparison:

	Energy Efficiency, Percent	Fuel or Electricity Purchase Costs $\frac{\text{Mills}}{\text{kilowatt-hour}}$
Cogeneration	80	12
Condensing Generation	22	44
Purchased Electricity	29	27

The distinction between cogeneration and condensing generation is vital for cost effectiveness analyses, even when both processes are going on simultaneously in the same piece of equipment.

SCOPE OF WORK

Objectives

The objectives of the study were to perform parametric cost analyses and site specific studies to determine if existing electric power generating facilities should be utilized. The facilities include existing boilers and existing steam turbine generators. The boilers were assumed to be fired with oil. Some of the components at the facilities were originally installed for standby power. The study evaluated the fuel use strategies for continuous on-base power generation with these facilities.

The evaluation determined whether on-base power generation:

- Leads to cost savings
- Leads to overall fuel savings if it is assumed that 11,600 Btu are required per kWh of purchased electricity.

General Systems Compared

In the general parametric study, nominal systems were configured in conceptual designs, and compared.

The common basis for the nominal systems were to:

- Satisfy heat and process steam demands up to 500 x 10^6 Btu/hr
- Supply the steam at 100 psig saturated
- Generate up to 20 megawatts, if turbine-generators are included in the systems.

The nominal systems included the following two configurations:

- A high pressure boiler with low temperature condenser is used for power generation in parallel with and completely separate from a low pressure boiler for heat and process steam.
- A high pressure boiler supplies steam to a turbine, with steam extraction capability for heat and process steam.

Measures for Comparison

The nominal conceptual system designs were ranked according to cost, efficiency, operability, and reliability. The cost analysis included the following:

- Capital costs of new facilities, provided with modular breakouts
- Capital costs per million Btu heating capacity of the system
- Annual operating and maintenance labor costs

- Annual energy costs

- Life-cycle costs using analysis methods and projected escalations of References 1, 2, and 3

- Assignment of relative cost factors between options compared

- Assignment of cost coefficients allowing extrapolation to systems with different capacities.

In computing life-cycle costs, a plant amortization life of 28 years was used, in accordance with Reference 4.

Parameters for Comparison

The following variables were examined parametrically in the nominal systems:

- Steam turbine inlet and outlet temperatures and pressures

- Temperature and pressure of extraction steam, when applicable

- Cost to interface extraction or turbine exhaust steam with the heat and process steam system, if applicable

- Boiler efficiency

- Fuel cost

- Electricity purchase cost

- Replacement cost of standby boilers and turbines used infrequently

- Replacement cost of standby boilers and turbines used continuously.

Site Specific Analysis

Current on-base electric power generation operations were examined at the following two facilities:

- Philadelphia Naval Shipyard

- Charleston Naval Shipyard

The results of the general analysis were used to determine if standby steam electric generating systems should be used for on-base power generation. The criteria for findings should be:

- Primarily cost reduction
- Secondarily, public utility fuel conservation.

The site specific studies were limited to electric power generating facilities and their interface with the heat and process steam system.

Visits to the two bases were conducted to obtain and verify data.

WORK PLAN

To meet the objectives above, the work on the study was organized into the following tasks:

1. Analyze steam states, processes, and cycles. This developed basic efficiencies and costs.
2. Define nominal systems for comparison. The systems selected included, in addition to the two required by the client, the following:
   - A reference case for comparison, which includes no on-base power generation facilities.
   - A turbine which can perform cogeneration but not condensing-generation.
3. Perform nominal energy use and cost comparisons. This task included:
   - Selecting typical electric and steam load profiles over daily, monthly, and yearly periods
   - Defining strategies for turbine use
   - Calculating energy and costs for each option with the given load profiles

4. Perform site specific energy use and cost comparisons. Where warranted, this included:

   - Interviewing site operators and managers
   - Inferring efficiencies and strategies from steam and electricity flows
   - Simplifying steam circuits for convenient analysis
   - Modeling the various alternative power generation strategies
   - Calculating energy use and costs for each strategy

5. Perform conceptual designs of nominal cases and variants. This included:

   - Designing balanced system steam and electricity flow networks
   - Specifying major equipment

6. Compute Costs. This included calculating capital, operating, and life cycle costs of the nominal cases and variants.

7. Prepare recommendations.

8. Prepare final report.

OUTLINE OF THE REPORT

In Section 3, steam states, processes, and cycles are analyzed. The attractiveness of cogeneration is first demonstrated there. In Section 4, several on-base generation options and variants are compared with no on-base generation in an energy use and cost study, assuming typical annual heat and power profiles. Peak shaving condensing generation is shown to be attractive in Section 4. Also, in Section 4, cost savings possible at Philadelphia are identified. Section 5 presents conceptual designs of eight options and variants. Section 6 presents capital, operating and life cycle costs of the variants of Section 5, by applying the energy use results from Section 4. Section 7 contains recommendations. Section 8 is a bibliography. There are six appendices.

Section 3

STATES, PROCESSES, AND CYCLES

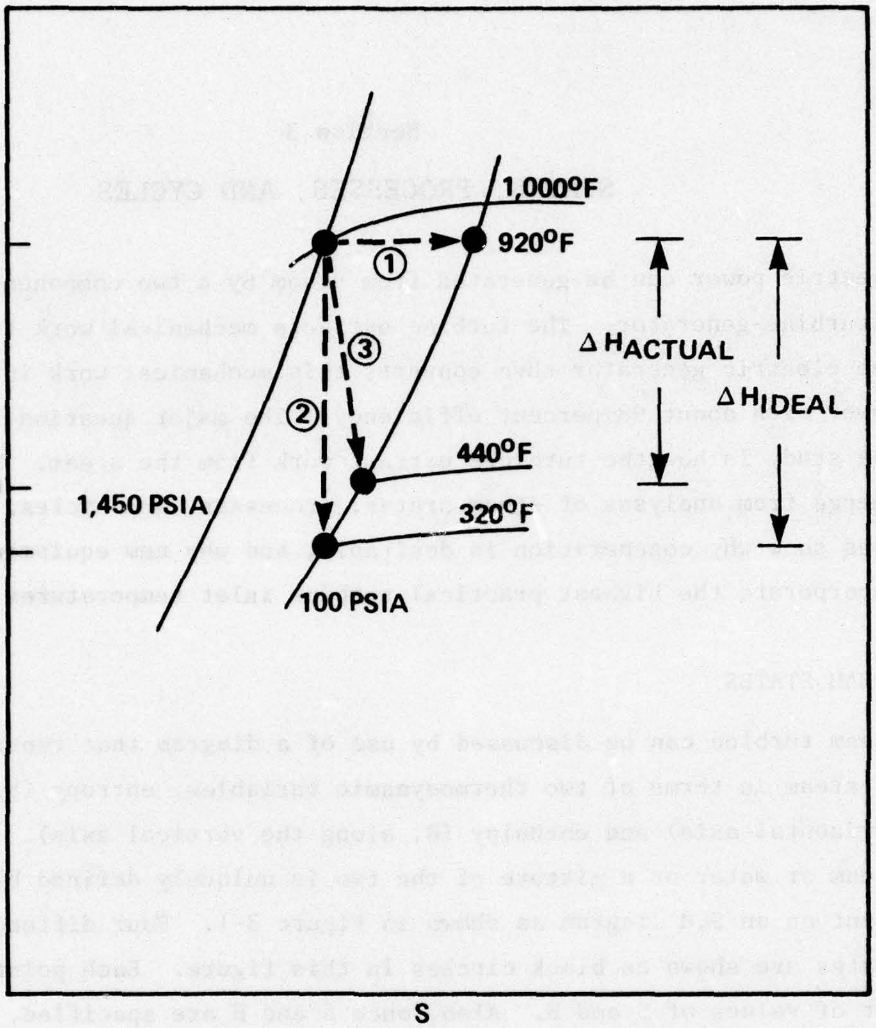
Electric power can be generated from steam by a two component device called a turbine-generator. The turbine extracts mechanical work from the steam. The electric generator then converts this mechanical work into electric power with about 98 percent efficiency. The major question in this energy use study is how the turbines extract work from the steam. The answers emerge from analyses of steam states, processes, and cycles. These analyses show why cogeneration is desirable, and why new equipment should incorporate the highest practical turbine inlet temperatures and pressures.

STEAM STATES

Steam turbine can be discussed by use of a diagram that represents states of steam in terms of two thermodynamic variables, entropy (S, along the horizontal axis) and enthalpy (H, along the vertical axis). A state of steam or water or a mixture of the two is uniquely defined by a single point on an S,H diagram as shown in Figure 3-1. Four different steam states are shown as black circles in this figure. Each point has a unique set of values of S and H. Also, once S and H are specified, other state variables, such as temperature and pressure, are uniquely defined. Figure 3-1 shows some typical constant temperature and constant pressure lines.

PROCESSES

A process is a transition between two states of steam. In Figure 3-1, three processes are shown with dotted lines. The final state is indicated by the arrow head. A process takes place in a specific piece of equipment.



① ISENTHALPIC EXPANSION (THROTTLE)
② ISENTROPIC EXPANSION (IDEAL TURBINE)
③ POLYTROPIC EXPANSION (ACTUAL TURBINE)

$\Delta H_{ACTUAL} / \Delta H_{IDEAL} \cong 0.8$

Figure 3-1. Steam States and Expansion Processes

Isenthalpic Expansion

Process 1 in Figure 3-1 takes place in a throttle valve. It is often referred to as a simple pressure let-down. The term "expansion" signifies that the volume occupied by a pound of steam increases as a result of the process, or alternatively that the pressure decreases. The term "isenthalpic" signifies that the value of enthalpy H is constant through the process. Enthalpy H is the measure of the energy that can be extracted from the steam. Since the enthalpy of the final state is the same after the process as before the process, no energy is extracted in a throttle valve expansion.

Isentropic Expansion

Process 2 in Figure 3-2 would take place by expansion in an ideal turbine. In this process, the gas pressure has decreased to the same final pressure as for Process 1. However, in Process 2 the final value of enthalpy is below the initial value. Therefore, the difference Δ_{ideal}, has been extracted as mechanical energy. The term "isentropic" for the process signifies that the thermodynamic variable entropy, S, is constant during the process. A constant entropy expansion is an ideal process which serves as a limit for turbine expansions. The difference ΔH_{ideal} is the largest amount of mechanical energy that can be extracted from each pound of steam, given an initial steam state and a final steam pressure.

Polytropic Expansion

Process 3 in Figure 3-1 takes place in an actual turbine. The same final pressure is achieved as for Process 1 and Process 2. However, the enthalpy change ΔH_{actual} that has taken place is only 80 percent of ΔH_{ideal} and the entropy, S, has increased. The ratio of $\Delta H_{actual}/\Delta H_{ideal}$ will be between 75 and 85 percent for turbines considered in this study.

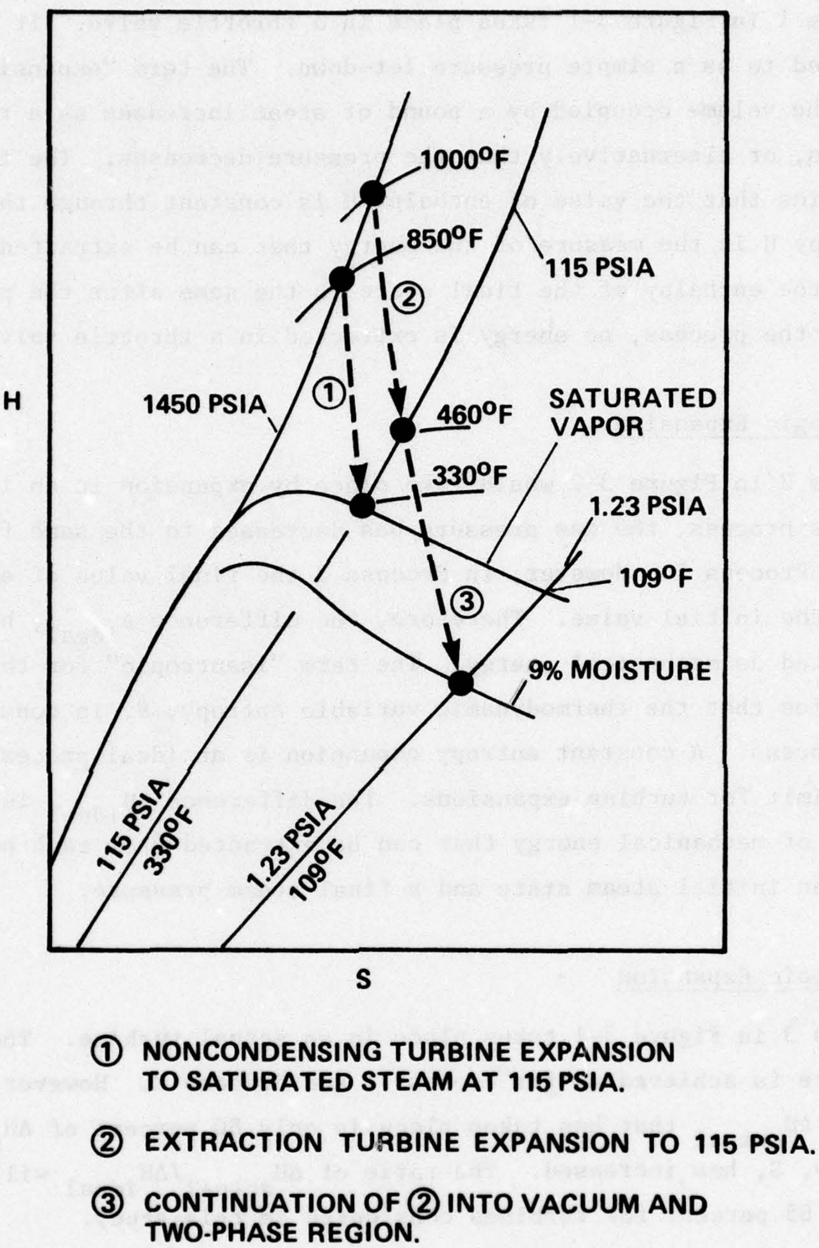


Figure 3-2. Noncondensing and Condensing Steam Turbine Expansion Processes

Noncondensing Expansion

Figure 3-2 shows the difference between a noncondensing expansion and a condensing expansion. Process 1 in Figure 3-2 is the expansion from 1,450 psia and 850°F to the conditions of saturated steam at 115 psia. A noncondensing expansion produces steam which can be used for heating. Useful steam and electricity are being generated together in a noncondensing expansion. This is strict cogeneration. Process 2 in Figure 3-2 is also a noncondensing expansion through the high pressure part of a condensing-extraction turbine. "Extraction steam" is the term given to the heating steam removed through the extraction port of such a turbine. When all the steam entering a condensing-extraction turbine is removed through the extraction port, the turbine is being used for cogeneration.

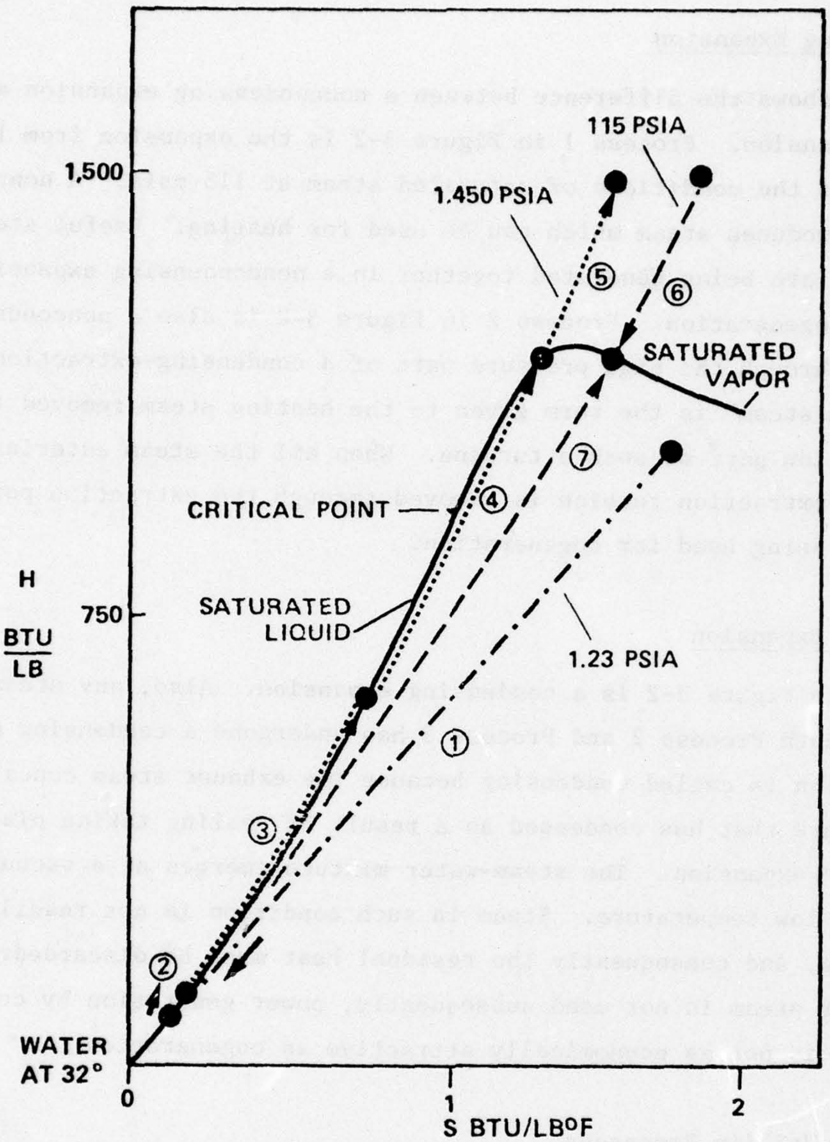
Condensing Expansion

Process 3 in Figure 3-2 is a condensing expansion. Also, any steam that undergoes both Process 2 and Process 3 has undergone a condensing expansion. The expansion is called condensing because the exhaust steam contains 9 percent moisture that has condensed as a result of cooling taking place during the turbine expansion. The steam-water mixture emerges at a vacuum pressure and a low temperature. Steam in such condition is not readily used for heating, and consequently the residual heat must be discarded. Because the exhaust steam is not used subsequently, power generation by condensing generation is not as economically attractive as cogeneration.

Additional Utility Processes

Figure 3-3 presents seven additional process steps in a steam power generation facility:

- Condensing vacuum exhaust steam. This takes place in a heat exchanger known as a surface condenser. The heat removed from the steam enters the cooling water that is flowing through the tube side of the exchanger. The cooling water emerges from the condenser warmer than when



1. CONDENSING VACUUM EXHAUST STEAM
2. PUMPING WATER
3. PREHEATING BOILER FEED WATER
4. BOILING OF WATER AT 1,450 PSIA
5. SUPERHEATING SATURATED STEAM
6. DESUPERHEATING STEAM
7. EVAPORATING DESUPERHEATER BLEND WATER

Figure 3-3. Additional Utility Steam Processes

it entered. It can either be returned in the warmed condition to the supply source, or cooled down in a cooling tower. In any case, the heat extracted from the vacuum steam is rejected or wasted. In fact, in all cases there are some costs associated with rejecting this heat.

- Pumping boiler feedwater. Boiler feedwater pumps put a small amount of enthalpy into the water, in addition to lifting the water to the desired boiler pressure.

- Preheating boiler feedwater. The water to be boiled usually is preheated in separate coils up to the boiling temperature before entering boiling tubes. During preheating, the temperature rises while the pressure stays approximately constant.

- Boiling water. This takes place in one bank of specially designed tubes inside a boiler. Boiling converts saturated liquid (water) into saturated vapor (steam) at a constant temperature and pressure.

- Superheating steam. The saturated steam emerging from the boiling tubes is heated to a higher temperature at constant pressure in superheat tubes, which are in a second specially designed tube bank in a boiler.

- Desuperheating steam. In some applications, more steam is occasionally needed for the heat loads than can be used in the turbines to satisfy the electric loads. The extra superheated steam must be throttled down to the heating steam pressure, and then cooled down to an acceptable heating steam temperature. This cooling of the steam is called "desuperheating." It is accomplished by blending the steam with water in a desuperheater.

- Evaporating desuperheater blend water. The water added to the desuperheater is completely evaporated and becomes part of the heating steam. If a tenth of a pound of water is blended with one pound of superheated steam, the product will be 1.1 pounds of desuperheated steam. Since the blend water will be completely evaporated, the water must be free of mineral impurities, or else scale deposits will accumulate in the heating steam lines downstream from the blending station. Two kinds of mineral-free water are acceptable for this service — condensate (formed from condensing steam) and water purified by a demineralizing ion exchange process. Simple softened water is not acceptable.

CYCLES

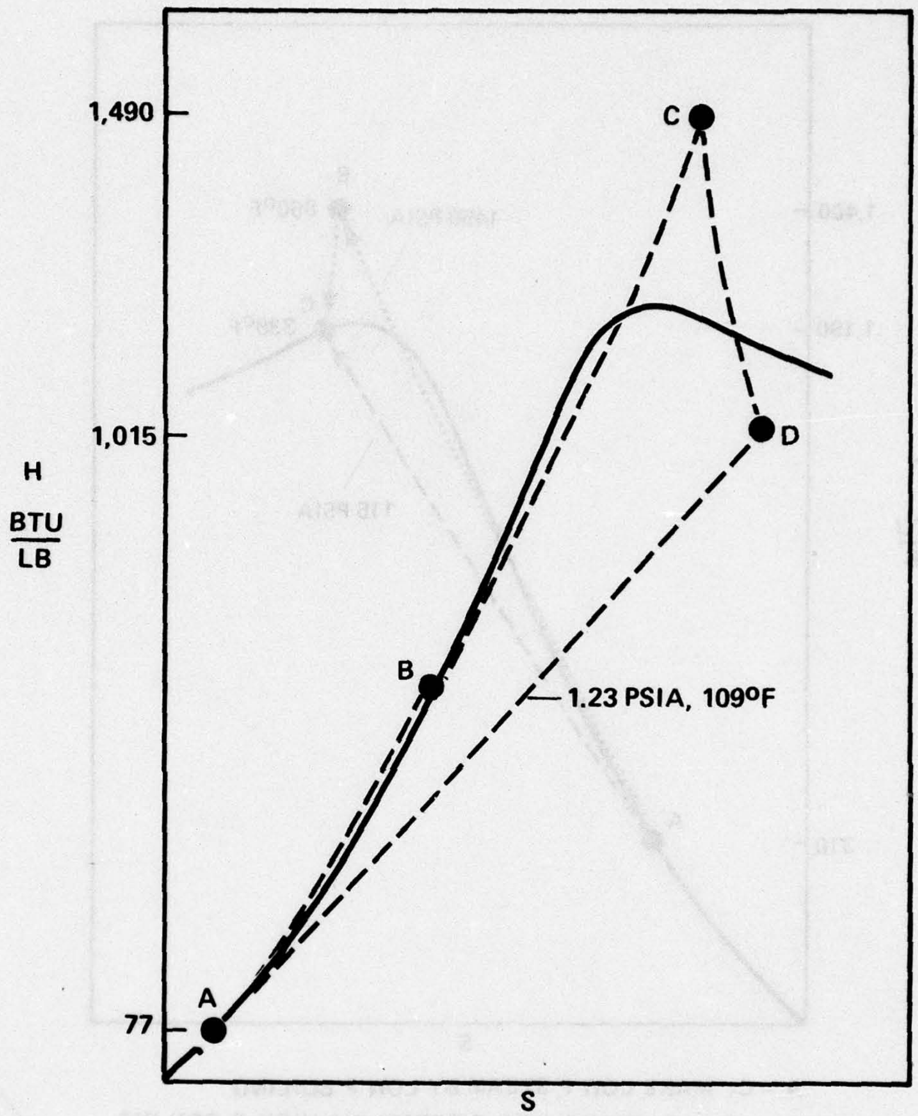
A single pound of steam can be circulated many times through the sequential processes in a steam-condensate system. A single complete loop is called a cycle. The final state of the steam in a cycle is the same as the starting state. It is instructive to consider the enthalpy changes in a complete cycle.

Condensing Generation Cycle

Figure 3-4 shows the cycle involved in generating, expanding and condensing high pressure high temperature steam. Most significant is that the steam system energy efficiency for power generation is 33 percent. This efficiency is approximately the highest efficiency that can be achieved in practical equipment at a medium sized industrial facility. Higher efficiencies can be achieved in large public utility systems by starting at pressures too high for medium sized equipment, and taking the steam through a second superheat process before introducing it into the condensing section of the turbine. Because public utilities can reach higher cycle efficiencies in power generation, power made by condensing generation at small industrial facilities will be at an economic disadvantage compared to purchased power. It should also be noted that the boiler has energy losses in converting fuel gross heat content into energy transferred into the steam. Some of the energy leaves the boiler as stack gas sensible heat and water vapor latent heat. A small additional amount is lost to the environment by heat transfer from boiler walls. Thus, boiler efficiencies are between 80 and 87 percent. The overall efficiency for power generation is the product of the steam system energy efficiency and the boiler efficiency.

Cogeneration Cycles

Figure 3-5 shows what is involved in cogeneration. Suppose there is a demand for a certain amount of heating steam at 115 psia and 338^{o}F. It must be generated in some way. A first alternative would be to generate



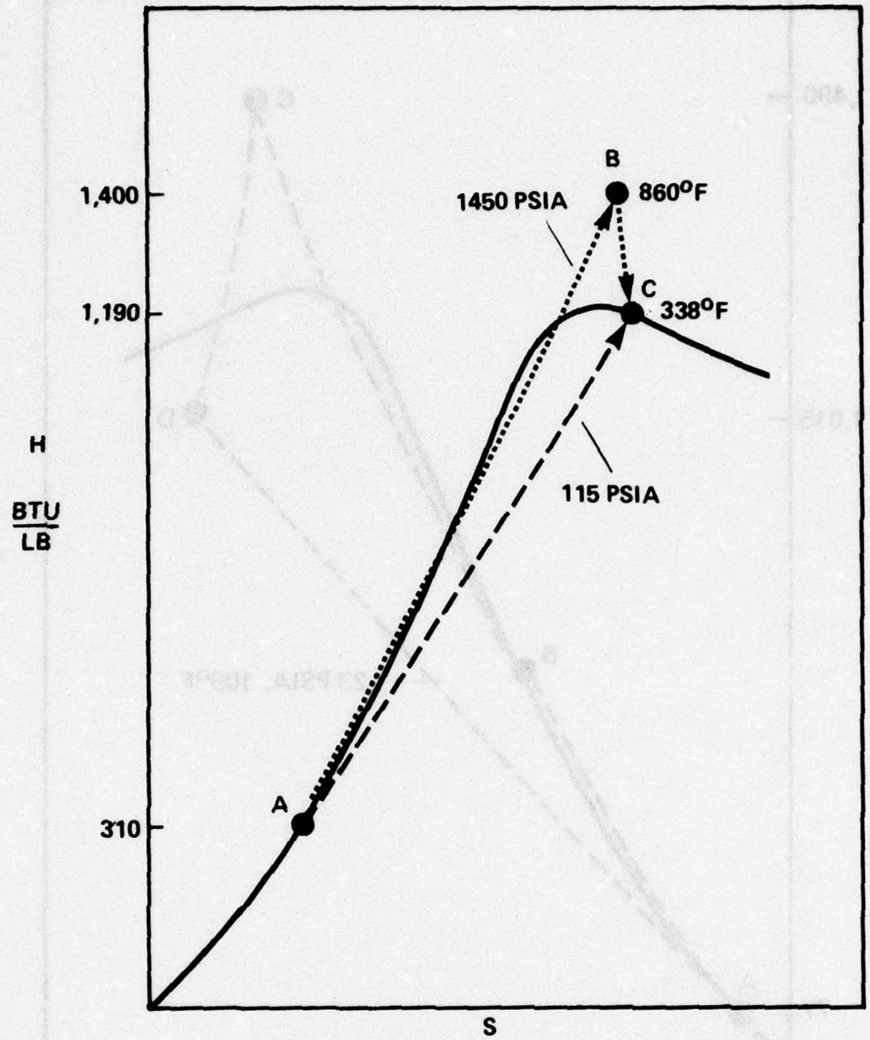
A–B–C: HEAT, BOIL, AND SUPERHEAT
C–D: EXPAND IN CONDENSING TURBINE
D–A: HEAT REJECTED IN VACUUM CONDENSER

(MECHANICAL POWER OUT) = $H_C - H_D$

(HEAT PUT IN FOR POWER GENERATION) = $H_C - H_A$

(STEAM SYSTEM ENERGY EFFICIENCY FOR POWER GENERATION) $= \dfrac{H_C - H_D}{H_C - H_A} = 0.33$

Figure 3-4. Condensing Generation Steam Cycle



A – C: MAKE LOW P STEAM BY LOW P BOILING

A – B – C: MAKE LOW P STEAM BY HIGH P BOILING AND TURBINE EXPANSION

(MECHANICAL POWER OUT) = $H_B - H_C$

(NET HEAT PUT IN FOR POWER GENERATION) = $(H_B - H_A) - (H_C - H_A) = H_B - H_C$

(STEAM SYSTEM ENERGY EFFICIENCY FOR POWER GENERATION) = $\frac{H_B - H_C}{H_B - H_C} = 1.0$

Figure 3-5. The Advantage of Steam Cycle Cogeneration

the steam directly at those conditions in a low pressure boiler. The second option is to generate the steam at a higher temperature and pressure, and expand it down to the required conditions in a turbine. The second alternative permits the extraction of mechanical work and generation of power. However, the amount of additional enthalpy put into the steam to raise it to point B instead of point C in Figure 3-5 is exactly equal to the amount of enthalpy converted to work in the expansion. Thus, the steam system energy efficiency is 100 percent for cogeneration. This is approximately three times as high as the condensing generation efficiency in the highest performance medium steam boiler turbine-generator facility that is practical. This explains why cogeneration can be attractive when condensing generation is unattractive.

Advantages of Higher Inlet Temperatures and Pressures

Figure 3-6 compares two condensing generation cycles that have different inlet conditions and the same exhaust condition. The figure reveals two advantages for higher inlet condition systems:

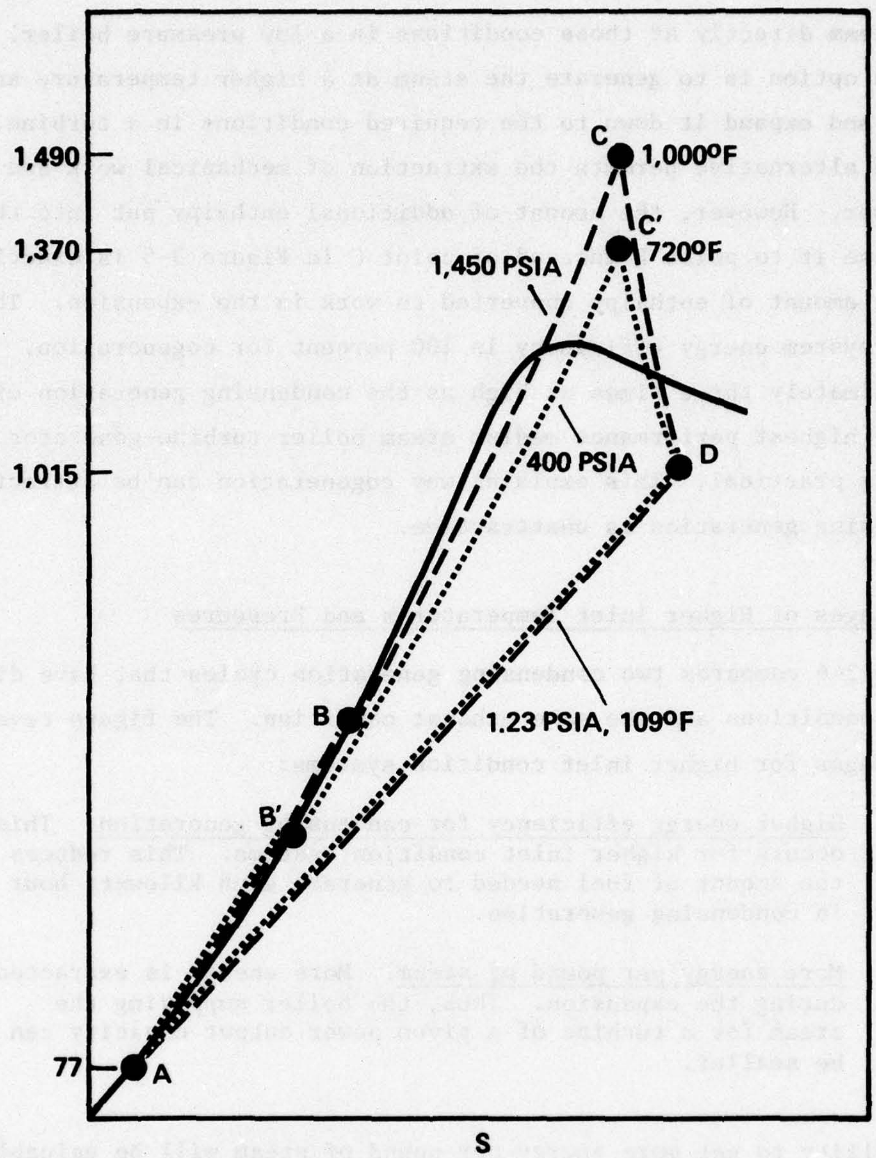
- Higher energy efficiency for condensing generation. This occurs for higher inlet condition systems. This reduces the amount of fuel needed to generate each kilowatt hour in condensing generation.

- More energy per pound of steam. More energy is extracted during the expansion. Thus, the boiler supplying the steam for a turbine of a given power output capacity can be smaller.

The ability to get more energy per pound of steam will be valuable also in cogeneration. There, with a fixed amount of heating steam passed through the turbines, more power can be generated.

Power Costs for Cogeneration and Condensing Generation

Table 3-1 compares purchased utility electric power with on-base power generation. The costs for power and fuel are typical of the northeastern



$$\left(\begin{array}{l}\text{STEAM SYSTEM EFFICIENCY}\\ \text{FOR POWER GENERATION,}\\ \text{HIGH T, P INLET CYCLE}\end{array}\right) = \frac{H_C - H_D}{H_C - H_A} = 0.33$$

$$\left(\begin{array}{l}\text{STEAM SYSTEM EFFICIENCY}\\ \text{FOR POWER GENERATION}\\ \text{LOW T, P INLET CYCLE}\end{array}\right) = \frac{H_{C'} - H_D}{H_{C'} - H_A} = 0.27$$

Figure 3-6. The Advantage of High Inlet Temperatures and Pressures: More Power Per Pound of Steam

United States. The comparison shows that cogeneration is quite attractive compared to purchased power on the basis of fuel use. The contrast between cogeneration and condensing generation shown here on the basis of simple cycle analysis is elaborated in the next section, which compares four conceptual generation facilities assuming typical steam and power load profiles.

Table 3-1

COST AND ENERGY COMPARISONS,
GENERATED VS PURCHASED ELECTRICITY

	Cogeneration	Condensing Generation		Purchased Electricity (N.E. U.S.)
		High T	Low T	
Inlet Temperature, ^{o}F	1,000*	1,000	720	—
Inlet Pressure, psia	1,450*	1,450	400	—
Steam System Efficiency	1.0	0.33	0.27	—
Boiler Efficiency	0.8	0.8	0.8	—
Overall Efficiency	0.8	0.27	0.22	0.29
Btu per kWh	4,265	12,730	15,530	11,600
Fuel Price $/10^6 Btu (N.E. U.S.)	2.81	2.81	2.81	—
Mills/kWh	12 (Fuel Only)	36 (Fuel Only)	44 (Fuel Only)	27 (Total)

* Any cogeneration inlet conditions give same results

Section 4

ENERGY USE AND COST COMPARISONS

Two energy use and cost analyses are presented in this section. In the first part of the section, four nominal power generation options are compared. They each satisfy a given typical steam and electric power demand profile. The results show the relative energy use and energy costs for alternative facilities in a size range typical for naval bases. The fuel and electricity purchase costs derived in this section will be combined with other operating costs and capital costs in Section 6, which presents the overall economics of existing and possible new facilities. In the second part of this section, power generation operations at Philadelphia and Charleston naval shipyards are examined.

STUDIES WITH NOMINAL POWER GENERATION OPTIONS

Four nominal power generation options have been selected to illustrate ways power can be provided to meet the demands at a typical navy base.

Facility Sizes

The facilities in the four options described below include the following common equipment features:

- Capacity for generating 500 x 10^6 Btu/hr of 100 psig steam
- 20 megawatt rating for any electric power generating components

Option 1, No On-Base Power Generation

The first option for power supply involves purchase of all the electricity needed, and no generation of electric power on the base. Conditions under which this energy use option occur include the following:

- No power generation facilities exist on the base
- Existing power generation equipment is out of service for repairs
- A decision has been made not to use a functioning generation system

Option 1 serves as a reference case against which power generation options are compared. The flow schematic for Option 1 is shown in Figure 4-1.

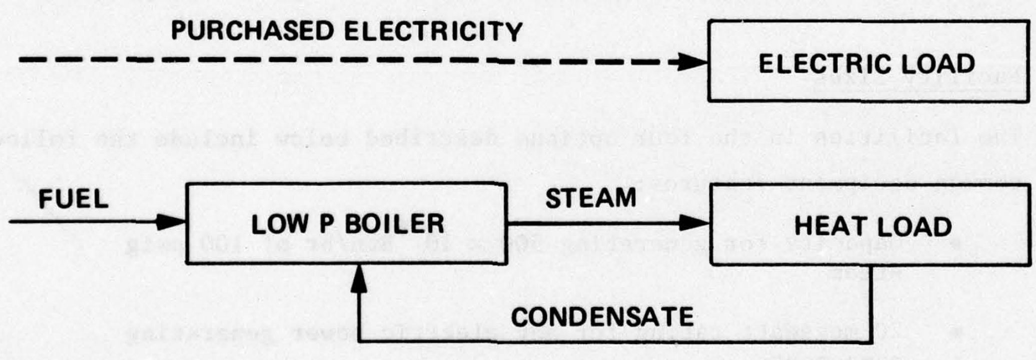


Figure 4-1. Systems for Power Supply, Option 1, No On-Base Power Generation

Option 2, Cogeneration

The second option provides for cogeneration of steam and electric power. Figure 4-2 shows the configuration of Option 2. Steam generated in a high pressure boiler can pass through a noncondensing turbine enroute to the heat load. The configuration also provides for extra steam to bypass the turbine, and allows for purchase of the difference between the electricity load and the electricity generated.

Figure 4-3 shows the performance diagram for the noncondensing turbine. The steam flow through the turbine and the corresponding electricity generated are found on the slanted line.

Three operating constraint lines are also shown in Figure 4-3:

- A horizontal line represents the steam flow W_L that can be accepted by the heat load at a given instant
- One vertical line represents the electricity flow M which can be accepted by the electric load at that same instant
- A second vertical line represents the maximum amount of power Q that can be generated by the equipment.

The maximum amount of power that can be generated at a given instant is the least of the constraints L, M, or Q, where L is the power generated corresponding to steam flow W_L. In Figure 4-3, the constraints are shown in the order of ascending power as L, M, and Q. However, at a given instant the three could be in any order.

Figure 4-3 shows a steam flow of 320,000 pounds per hour corresponding to 20 megawatts of generation. The ratio of 16,000 pounds per megawatt-hour is characteristic of a turbine with 1,450 psia, 830^{o}F inlet temperature and pressure.

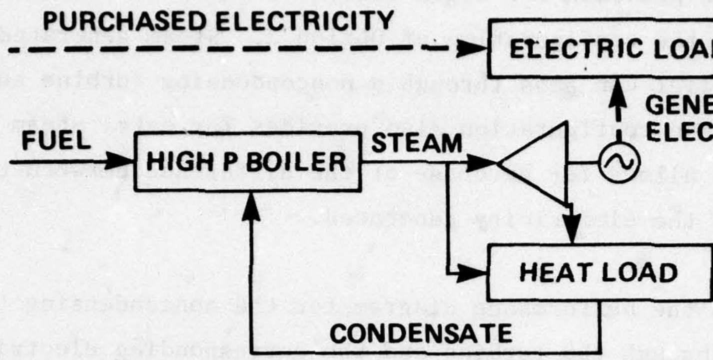


Figure 4-2. Systems for Power Supply, Option 2, Cogeneration

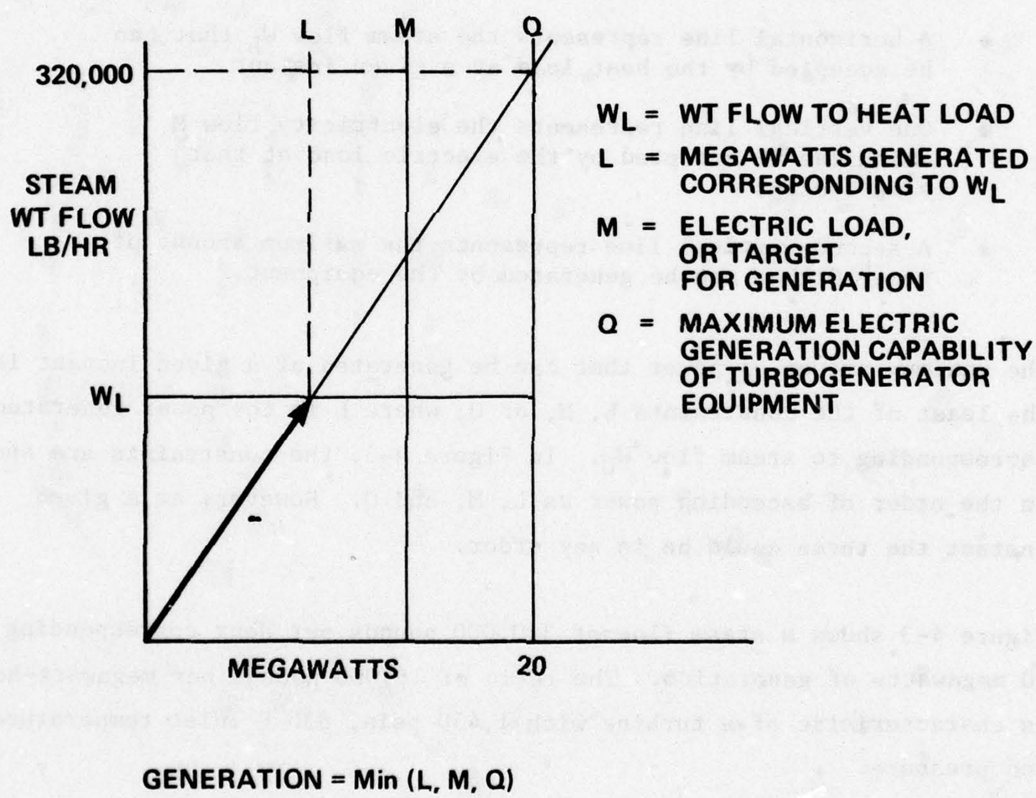


Figure 4-3. Noncondensing Turbine Settings in Option 2, Cogeneration

Option 3, Condensing Generation

Figure 4-4 presents the configuration of a system with condensing generation as the only type of on-base power generation. Whenever a pound of steam is used in condensing generation, it cannot be used afterwards for heating. Accordingly, Figure 4-4 presents heat load steam and power generation steam on two entirely separate and disconnected circuits. It is very helpful for energy use analysis to visualize condensing generation steam as on a separate circuit from steam intended for heat loads. The fact that most facilities include interconnections between the condensing generation and heating steam circuits tends to confuse this vital distinction.

Figure 4-5 presents the performance diagram for a condensing turbine. The slanted line is less steep than in Figure 4-3; less steam is needed to make 20 megawatts by condensing generation than by noncondensing generation. However, this should never obscure the fact that condensing generation is intrinsically less desirable than cogeneration on the basis of fuel use. In Figure 4-5, the steam to power ratio is 7,500 pounds per megawatt hour. This corresponds to 1,450 psia, 1000^{o}F inlet conditions and exhaust conditions at 1.23 psia and 9 percent moisture.

Only the constraints M and Q limit power generation in Figure 4-5. However, for reasons that will be clear later, M may often be set as a target generation amount not to be exceeded, rather than the full amount of the electric load at a given instant. The amount to be generated at any moment is the smallest of M and Q.

Option 4, Combined Cogeneration and Condensing Generation

Figure 4-6 shows the configuration for the fourth option, which combines the features of both Options 2 and 3. Even though condensing generation may be uneconomical on the basis of fuel use alone, there may be cogent reasons for including a condensing generation capability in a plant. Consequently, Option 4 appears to be the correct configuration to install at

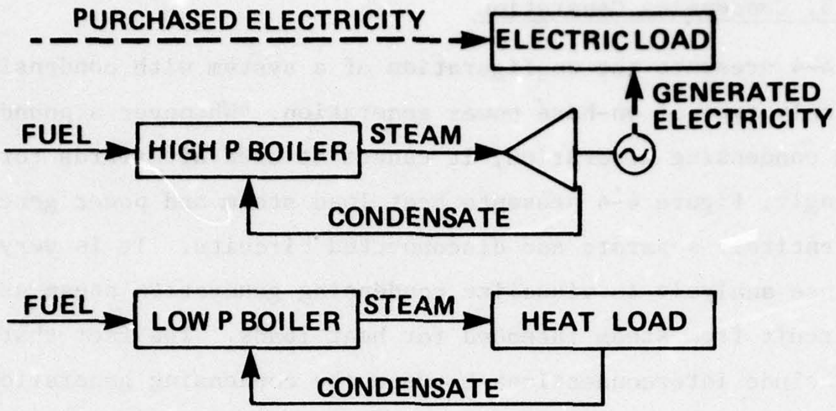


Figure 4-4. Systems for Power Supply Option 3, Condensing Generation

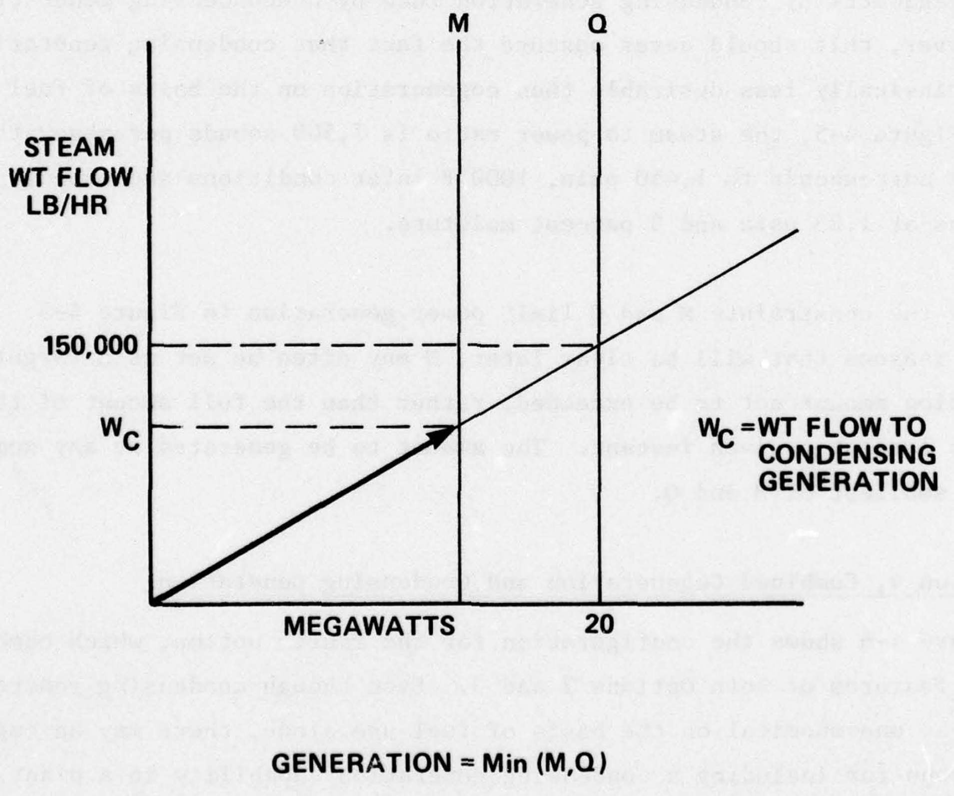


Figure 4-5. Condensing Turbine Settings in Option 3, Condensing Generation

most naval facilities that must generate power. Option 4 includes a turbine that can be used simultaneously for both cogeneration and condensing generation. The turbine is known as an automatic extraction turbine of the condensing type. It can be controlled by two flow control valves, one controlling the flow from the extraction point to the heat load for cogeneration, and one which controls the inlet flow. The flow to condensing generation is the difference between the inlet and extraction flows.

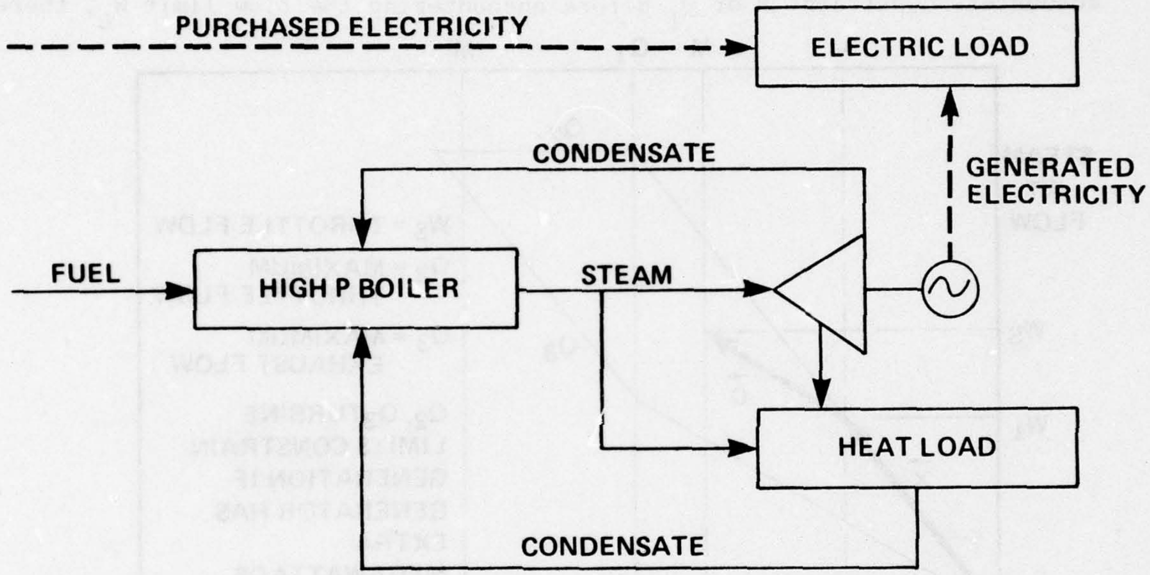


Figure 4-6. Systems for Power Supply Option 4, Combined Cogeneration and Condensing Generation

Figure 4-7 presents the performance diagram* for the condensing-extraction turbine used in Option 4. Note that there are two slanted lines sloping up from the origin to intersect the 20 megawatt constraint line. The steep line is approximately parallel to the operating line for the noncondensing turbine shown in Figure 4-3. Any portion of steam flow intended

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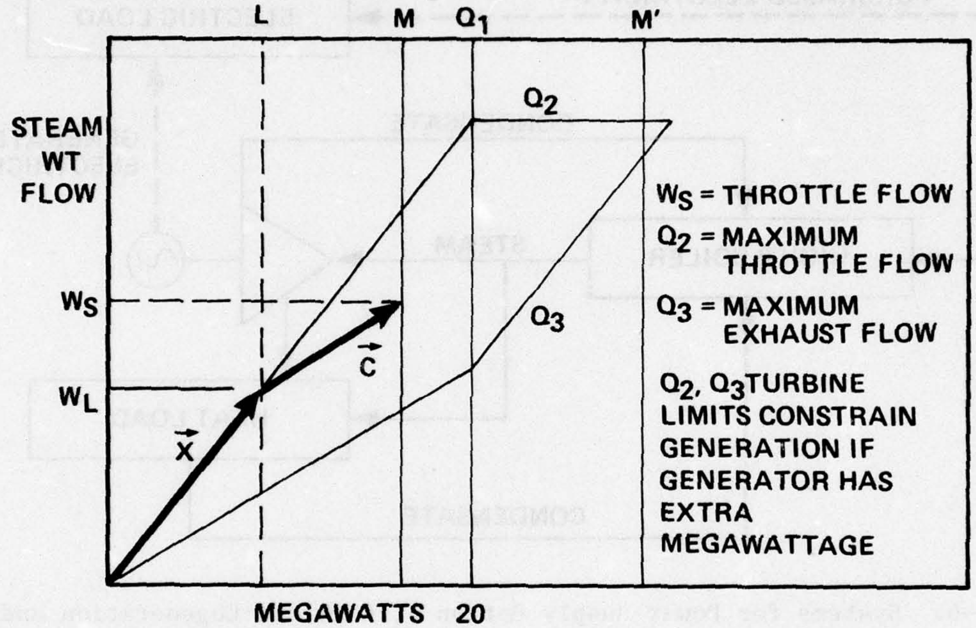
* A diagram of this type is provided by most vendors along with each automatic extraction turbine purchased. Such a diagram is also discussed in the General Electric Equipment Price Catalogue, 1976 Edition, Section 4726 (Industrial Steam Turbine-Generator Units), page 45.

for extraction and cogeneration will be represented as an arrow $\vec{X}$ parallel to this steep line. The shallow line is identical with the operating line for the condensing turbine in Figure 4-5. Any portion of steam flow intended for condensing generation should be drawn as an arrow $\vec{C}$, parallel to this shallow line. To get the total power generated and the total steam flow, add the two arrows vectorially. The best way to add them vectorially requires a strategy. Since it is already clear that cogeneration is preferable to condensing generation, the correct strategy is to draw the cogeneration arrow $\vec{X}$ first, starting at the origin. If the cogeneration arrow encounters constraint M or Q_1 before encountering the flow limit W_L, there



X_{MW} = EXTRACTION GENERATION = Min (L, M, Q_1)

C_{MW} = CONDENSING GENERATION

= Min (M, Q_i) – EXTRACTION GENERATION

OR = 0.0

X_{MW} AND C_{MW} ARE COMPONENTS OF VECTORS $\vec{X}$ AND $\vec{C}$ ALONG THE MEGAWATT (HORIZONTAL) AXIS.

Figure 4-7. Condensing Extraction Turbine Setting in Option 4, Combined Cogeneration and Condensing Generation

would be no additional generation needed in the condensing mode, and there would be no condensing generation arrow on the diagram. If the cogeneration arrow encounters constraint flow W_L before M or Q_1, the condensing arrow $\vec{C}$ should be drawn with its origin at the head of arrow $\vec{X}$.

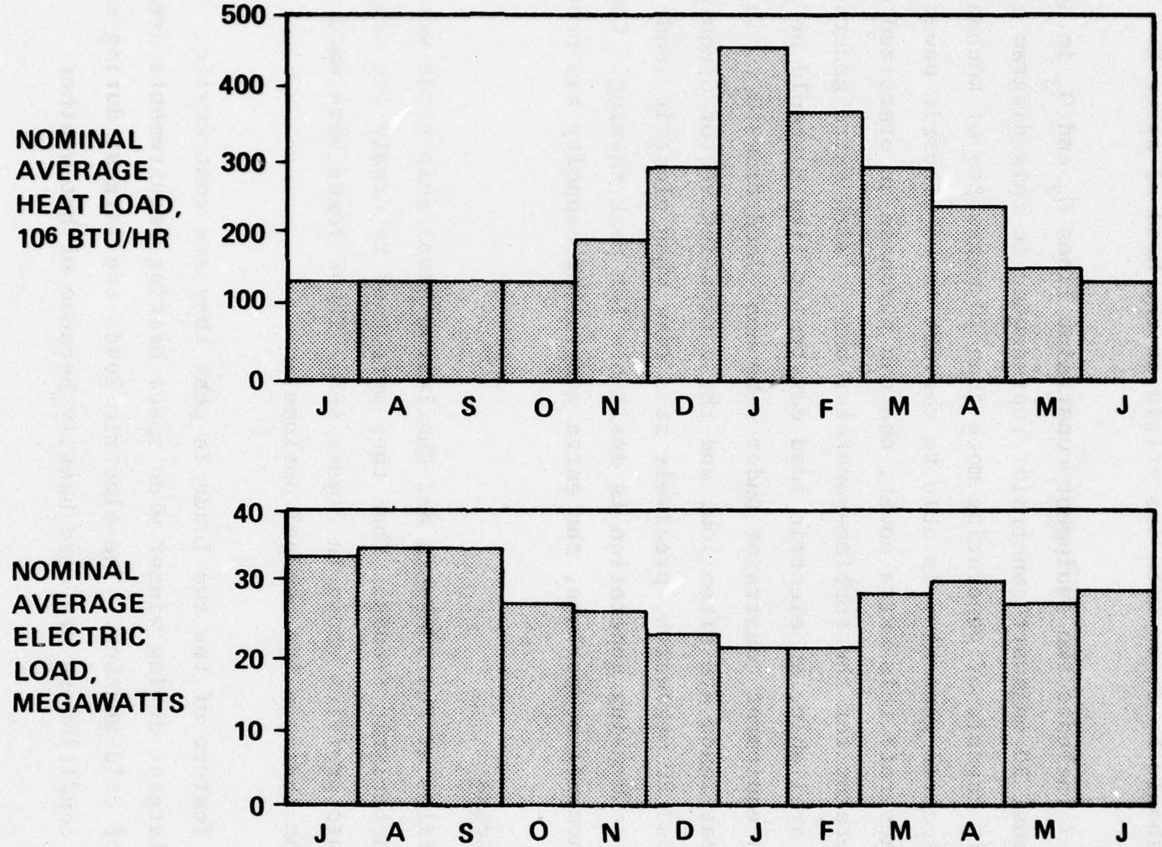
Figure 4-7 includes two equipment constraint lines Q_2 and Q_3 in addition to the usual 20 megawatt constraint represented in this diagram as Q_1. The turbine is capable of generating more than 20 megawatts of mechanical power, if the electric generator is able to convert it to electric power. To be able to generate this extra power, one can purchase an oversized electric generator for the turbine-generator unit. With extra generating capacity available, an electric load constraint like M' could be reached before an equipment constraint under some heat load flows W_L. In fact, summer heat loads are often low, and the condensing vector $\vec{C}$ could extend well beyond 20 megawatts, precisely at a time when electric loads are highest, and condensing generation is desirable for peak shaving. Consequently, in this nominal comparison, the extra generating capacity has been assumed.

Nominal Loads

Load profiles at Philadelphia and Charleston naval ship yards were analyzed for characteristic trends. Then they were used to create the nominal annual load profiles shown in Figure 4-8. These loads were used in the comparisons between the nominal options.

The main feature of the two loads is that they are contracylic. The heat load is largest during winter when space heating requirements are large because of cold weather. The electric loads are largest during summer, when air conditioners are used heavily because of hot weather.

It is because the maximum electricity and heating loads are out of phase that the highest practical turbine inlet steam temperatures and pressures are favored in cogeneration.



NOTE: ALL DAYS IN A GIVEN MONTH ARE ASSUMED TO HAVE THE SAME LOAD PROFILES

Figure 4-8. Nominal Heat and Electricity Loads

Additional assumptions about the load profiles are as follows:

- Each day of a given month is assumed to have the same profile.
- The heating load is assumed to be constant over the month.
- The peak electricity load of each month is assumed to be 1.57 times the average load for the month.
- Each day of a month has a 14.4-hour night period with a continuous load that is 86 percent of the monthly average.
- Each day has a 9.6-hour day period with a continuous load 21 percent higher than the average. It also has a zero width needle peak extending to the peak monthly load.

It should be noted that the average electric load in Figure 4-8 for each month is above the rated generating capacity (20 megawatts) for turbines used in the last three options. Charleston is one example where the load exceeds the equipment. This feature was chosen to allow calculation simplifications. The contrary case, with generation capability greater than the average load, will be considered in the study of Philadelphia operations.

Fuel and Electricity Prices

The fuel price used in the studies in this section was inferred from the utility cost accounting report for the Philadelphia Naval Shipyard in fiscal year 1976. The price was $\$2.86/10^6$ Btu. That price was the composite of purchases of fuel oil in the winter and less expensive natural gas during the summer. The boiler efficiency used in the comparisons was 83 percent (corresponding to combustion of natural gas). The same annual total fuel purchases would occur with a boiler efficiency of 87 percent (corresponding to fuel oil combustion) and a fuel price of $\$3.00/10^6$ Btu.

The electricity price is actually computed from a formula with features as shown by the curves in Figure 4-9. The curves show that the price of electricity in a given month depends on the ratio of the monthly average comsumption to the annual peak consumption. The price curve resembles the 1977 electricity price schedule for Philadelphia Naval Shipyard.

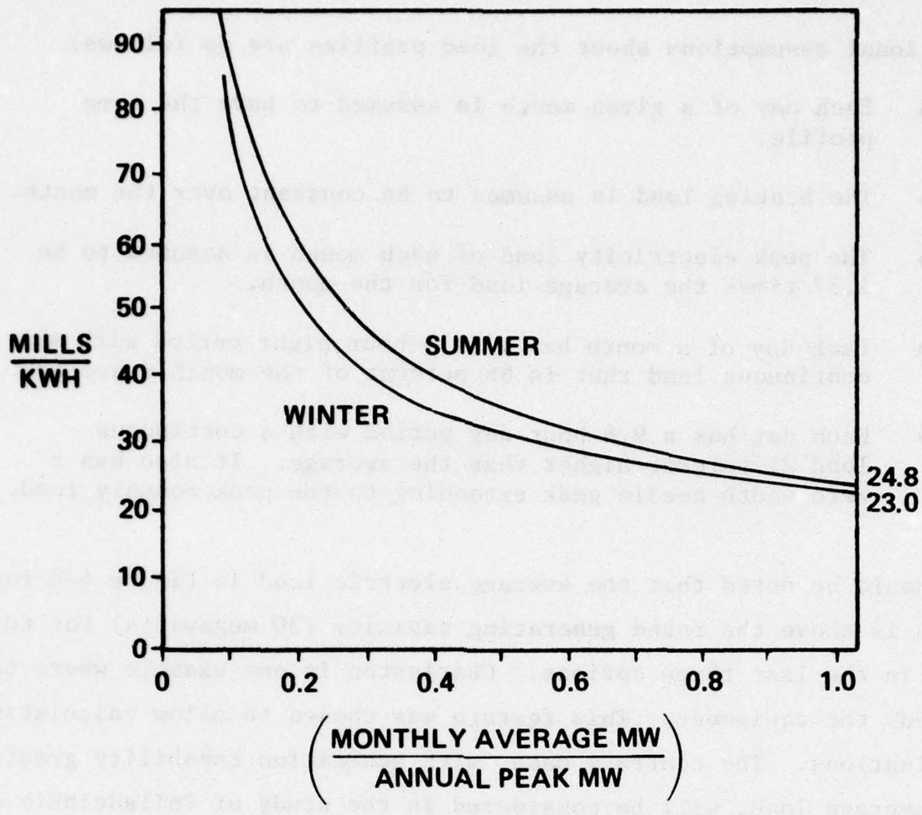


Figure 4-9. Average Monthly Electric Power Price

<u>Comparison of the Four Options</u>

The four options presented earlier in this section are compared in Table 4-1 and in more detail in Appendix A. Cogeneration is shown to give savings relative to the purchase of all electric power. Constant base loaded condensing generation is economically unattractive. Two other implications of the comparisons are described in the following paragraphs.

<u>Cogeneration Most Attractive with High Inlet T and P</u>

Table 4-1 compares an Option 2A having low inlet temperature and pressure with Option 2 as previously described, having high inlet temperature and pressure. The option with the high inlet conditions gives the greatest

Table 4-1

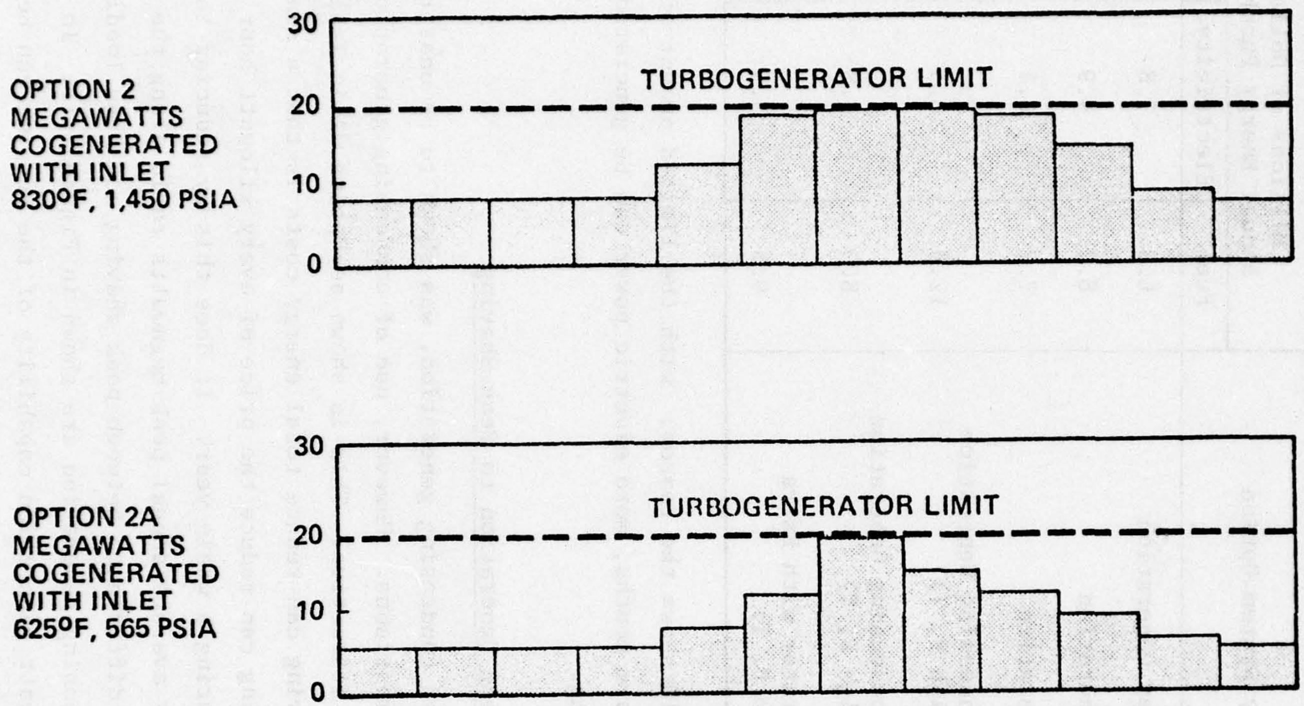
ENERGY COST COMPARISONS FOR NOMINAL LOADS

Power Supply System Option		Millions of Dollars Annual Energy Purchases		
		Fuel	Electricity	Total
1	No On-Base Power Generation	6.8	7.8	14.6
2	High T, P Cogeneration	8.2	4.9	13.1
2A	Low T, P Cogeneration	7.7	6.1	13.8
3	Base Loaded Condensing Generation (High P, T)	12.9	3.3	16.2
3A	Peak Shaving Condensing Generation (High P, T)	8.0	5.8	13.8
4	Combined, Generator with Extra Capacity (High P, T)	9.5	3.5	13.0

savings. Figure 4-10 shows the reason: with the limited amount of heating steam demanded in warm months, more electric power can be generated with high inlet conditions.

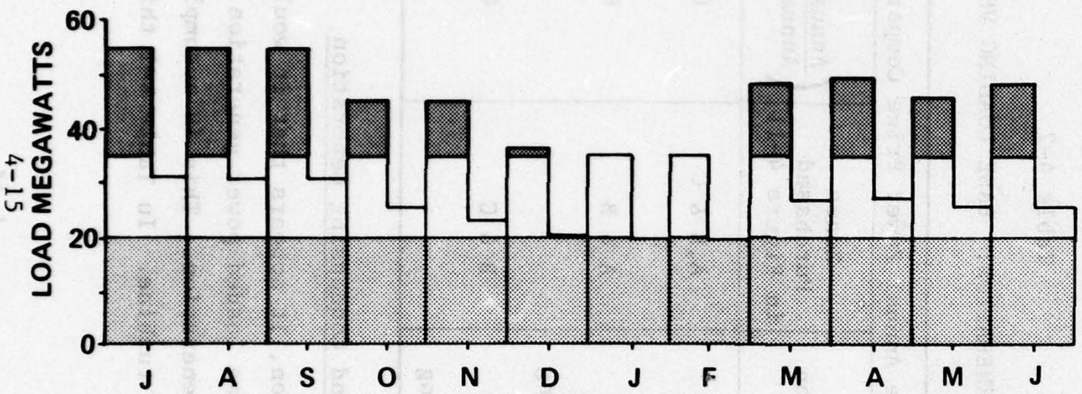
Restricting Condensing Generation to Peak Shaving

Option 3, base loaded condensing generation, was shown to be unattractive by the Table 4-1 comparisons. However, use of condensing generation for peak shaving can be attractive. This is shown as Option 3A in Table 4-1. The reason peak shaving can reduce total energy costs is that a small amount of peak shaving can reduce the price of every kilowatt hour of electricity purchased during a whole year. It does this by reducing the denominator in the monthly average/annual peak megawatts ratio along the X axis in Figure 4-9. The differences between peak shaving and base loading strategies for condensing generation are shown in Figure 4-11. In that figure, the 20 megawatt generation capability of the turbine can be used



THE SHADED AREA REPRESENTS POWER FROM COGENERATION.
MORE ELECTRICITY IS GENERATED BY THE TURBINE OF OPTION 2
USING THE SAME FLOW OF STEAM, FOR THE MOST MONTHS OF THE YEAR .

Figure 4-10. The Advantage of High Inlet T and P in Cogeneration



ZONE	THICKNESS	SIGNIFICANCE
A	20 MW*	GENERATED IF PEAK SHAVING
B	15 MW	
C	20 MW*	GENERATED IF BASE LOADING

*EQUIPMENT LIMIT

Figure 4-11. Condensing Generation Strategy Options

either to generate continuously or merely to generate intermittently to reduce the annual peak purchase by 20 megawatts. The effect on the annual average to annual peak purchase ratio and on the average annual electricity price is shown in Table 4-2. The small amount of peak shaving generation reduced the annual electricity price by four mills/kWh compared to purchase of all the power. On the other hand, use of the turbine for base loaded generation will compete with the public utility directly, using an intrinsically less efficient energy cycle, and also will force the electric utility to do the peak shaving and to install the necessary extra capacity. The combined result is the very high power price shown for Option 3 in Table 4-2.

Table 4-2

CONDENSING GENERATION: BASE LOADING VS PEAK SHAVING

Average Annual Power Price Comparison				
Option	Description	Zones Purchased in Figure 4-11	$\left(\frac{\text{Annual Avg.}}{\text{Annual Peak}}\right)$	Annual Average Price Mills/kWh
1	No On-Base Generation	A,B & C	0.52	31.1
3	Condensing Generation Base Loading	A & B	0.16	43.3
3A	Condensing Generation Peak Shaving	B & C	0.71	26.9

Combined Cogeneration and Condensing Generation

From the above discussion, it appears that it would be attractive to have a system that can do base loaded power generation by cogeneration and peak shaving by condensing generation. This is accomplished by Option 4 with a condensing-extraction turbine. In Table 4-1 this option is slightly more

attractive than Option 2, pure cogeneration. Because of its great flexibility and its ability to provide power in emergencies, the Option 4 configuration will usually be required at Navy bases. However, Table 4-1 does not support a conclusion that combined cogeneration and peak shaving condensing generation is dramatically superior to pure cogeneration alone, nor does it indicate whether the extra power capacity was advantageous for peak shaving. In fact, operations at Philadelphia Naval Shipyard suggest that the amount of peak shaving required should be selected by a tradeoff study each year, and that the extra capacity in Option 4 may, in most cases, be valuable primarily as an extra capability for emergencies.

POWER GENERATION AT PHILADELPHIA NAVAL SHIPYARD

Current power generation operations at Philadelphia Naval Shipyard are described in Appendix B. They are currently generating 40 percent of the electrical load at all times. A special simulation calculation was made in this study to determine whether Philadelphia Naval Shipyard could realize cost savings by making optimal use of their equipment. Details of the simulation calculation are provided in Appendix C.

Salient facts about Philadelphia operations useful for understanding the results of the simulation are the following:

- The monthly average heating load ranges from 150×10^6 Btu/hr in the summer to 500×10^6 Btu/hr in midwinter.
- The monthly peak electric load ranges from 32 megawatts in midsummer to 25 megawatts in winter.
- The monthly average electric load ranges from 19 megawatts in midsummer to 12.5 megawatts in the winter.
- The complement of four turbines can be approximated quite well by a single condensing-extraction turbine that can generate 20 megawatts in either the pure cogeneration mode or the pure condensing generation mode, and up to 20 megawatts for all combinations of the two generation modes.

- Philadelphia does not yet have its demineralizing plant reactivated. Therefore, they need to use condensate to desuperheat bypass steam.
- Philadelphia makes both 200 psig heating steam and 60 psig heating steam. The amount of 200 psig steam that can be made by turbine extraction is limited, so in midwinter, most of the 200 psig steam must be made by desuperheating steam that bypasses the turbines. The simulation calculation assumed that half the steam over 80,000 lb/hr was 200 psig steam that bypassed the turbines. Also, the simulation calculation assumed that the mix of 200 psig steam and 60 psig steam produced could be approximated by a single stream of 100 psig steam.

The results of the simulation calculation are given in Table 4-3. In that table, the last four cases follow Bechtel's generation strategy. That strategy calls for continuous cogeneration to the maximum extent possible and condensing generation for peak shaving. The first case is Philadelphia's current strategy. The second case assumes all electricity is purchased. The third case is the result when cogeneration alone is performed.

The major conclusions are shown in Table 4-4: close to $600,000 per year could possibly be saved without any capital expenditure, merely by modifying the way the existing turbines are used at Philadelphia; an additional $170,000 per year can be saved by completing the reactivation of the demineralizer. The total saving approaches $800,000 per year.

It should be noted that because the savings predicted in Table 4-4 are approximate, a more accurate estimate of the savings would result from more extensive calculation. However, a more detailed calculation was beyond the scope of this contract. Some incentive exists to have additional optimizing calculations done in the future to guide Philadelphia's generation policy. This is indicated by Table 4-3, which shows that missetting the peak purchased electricity by two megawatts can lead to a loss of $110,000 per year in savings. The sensitivity of energy costs to the annual peak purchased power is shown in Appendix C.

Table 4-3

PHILADELPHIA NAVAL SHIPYARD GENERATING
FACILITY SIMULATION RESULTS

Case Number	Generation Strategy	Peak Purchased MW	Fuel Plus Electricity Annual Purchases 10^{12} Btu's*	Fuel Plus Electricity Annual Purchases 10^{6} Dollars **
1	Current Philadelphia strategy (generate 40% of load)	19.1	4.12	11.37
2	Buy all electricity, generate none	32.1	4.21	11.44
3	Cogenerate only, no condensing generation	28.5	3.88	11.00
4	Bechtel strategy; no demineralizer; maximum possible shave (20 MW maximum)	12.1	4.05	10.86
5	Bechtel strategy; no demineralizer; optimum shave (18 MW maximum)	14.1	3.98	10.76
6	Bechtel strategy; with demineralizer; maximum possible shave (20 MW maximum)	12.23	4.00	10.71
7	Bechtel strategy, with demineralizer; optimum shave (17.85 MW maximum)	14.25	3.95	10.59

* Purchased electricity Btu's taken as 11,600 Btu/kilowatt hour.

**Electricity prices were as shown in Figure 4-9, except that the abscissa ratio for Philadelphia should read "(Monthly Average MW/Billing Demand MW)." See the last paragraph in Appendix B.

Table 4-4

ENERGY AND COST SAVINGS POSSIBLE WITH
BECHTEL STRATEGY AT PHILADELPHIA NAVAL SHIPYARD

	Savings in Annual Purchases of Fuel Plus Electricity	
Bechtel strategy case compared with current strategy Case 1	10^6 Btu's	Energy Costs
Case 5 without demineralizer	140,000	$610,000
Case 7 with demineralizer	170,000	$780,000

The reasons for the results in Table 4-3 are suggested by tabulations in Table 4-5. In this table, parameters relating to purchased power and generated power are presented. The most interesting facts are that the current generation strategy incurs higher average power costs than Bechtel strategy Cases 4 to 7, it takes advantage of less cogeneration flow, and it has the highest flow of condensing generation steam. This explains why such substantial savings can be obtained by switching to Bechtel's recommended strategy.

The comparisons between Cases 4 and 5 and Cases 6 and 7 show how an optimum must be sought in the tradeoff between reducing the purchased electricity price by peak shaving and reducing fuel costs by restricting condensing generation.

POWER GENERATION AT CHARLESTON NAVAL SHIPYARD

Appendix D contains a description of the power generation operations at the Charleston, South Carolina Naval Shipyard. The electric loads at Charleston range up to 40 megawatts. They have a 5 megawatt turbine-generator unit which can make power either by cogeneration or condensing generation. The cogeneration process is actually low in performance (inlet pressure 400 psig, extraction pressure (170 psig). The managers have determined that operating

Table 4-5

POWER PURCHASE AND GENERATION PARAMETERS
FOR PHILADELPHIA NAVAL SHIPYARD SIMULATION COMPARISONS

Case	Electricity Generating Strategy	Purchased Power		Generated Power		
					10^3 lb/hr Steam Annual Average	
		Annual Average MW / Annual Peak MW	Price, Mills / kWhr	Cogen. MW / Total Gen. MW	To Cogeneration	To Condensing Generation
1	Current, generate 40% of load	.55	28.4	.46	94	52
2	Purchase 100%	.53	29.0	—	—	—
3	Cogenerate, no peak shave	.42	32.0	1.0	162	—
4	Cogenerate, plus maximum peak shave, no demineralizer	.80	24.7	.55	129	46
5	Cogenerate, plus optimum peak shave, no demineralizer	.72	25.9	.67	146	34
6	Cogenerate, plus maximum peak shave, with demineralizer	.82	24.3	.63	139	39
7	Cogenerate, plus optimum peak shave, with demineralizer	.75	25.6	.75	152	24

and maintenance labor and material costs would outweight energy cost savings in cogeneration. Therefore, the turbine is used only for peak shaving.

The current power generation policy at Charleston Naval Shipyard appears satisfactory. At Charleston with coal costs of $1.34 per 10^6 Btu, the fuel cost for cogeneration is quite low, 5.4 mills per kilowatt-hour. Purchased power at Charleston, by contrast, costs approximately 20 mills per kilowatt-hour. For this reason, they may want to reevaluate continuous cogeneration.

Section 5

NEW OIL-FIRED FACILITY DESIGNS

CONFIGURATION OPTIONS

Conceptual designs were prepared for eight different facility configurations to allow comparison of capital costs as well as energy costs for the four basic use options developed in Section 4. In this section, the philosophy for selecting equipment for each configuration option is set forth. A summary of equipment details for each configuration is provided in Appendix E.

Option 1, No On-Base Generation

Option 1 is a facility that does not generate electric power. Consequently, only low pressure boilers producing 100 psig saturated steam are needed. A single boiler transferring heat at a rate of 500×10^6 Btu/hr is included. This boiler generates approximately 500,000 lb/hr of steam. One operating and one spare boiler feedwater pump are provided. Because the steam is generated at low pressure and temperature, softening is the only water treatment required. The boiler contains an air preheater, and has an 87 percent efficiency when burning oil.

Option 2, High Temperature and Pressure Cogeneration

Option 2 includes a 20 megawatt noncondensing steam turbine-generator which accepts steam at 830^oF and 1,450 psia, and exhausts it as 100 psig saturated steam. To generate 20 megawatts, 320,000 lb/hr of steam must pass through the turbine. Consequently, the system requires a high pressure boiler producing 320,000 lb/hr. In order to meet a maximum steam demand of 500,000 lb/hr, a low pressure boiler has been included which makes 180,000 lb/hr of saturated 100 psig steam. The configuration must include a demineralizer for the 320,000 lb/hr of water that enters the high pressure boiler,

but the balance can be softened. Separate pairs of pumps serve the two boilers. An electrical switching station is needed to mesh the 20 megawatts of power from the turbogenerator with the existing circuitry for power distribution on the Navy base.

Option 2A, Low Temperature and Pressure Cogeneration

Option 2A contains a 20 megawatt noncondensing steam turbine-generator which accepts steam at 625^{o}F and 565 psia and discharges it as 100 psig saturated steam. This turbine requires a steam flow of 500,000 lb/hr to generate 20 megawatts. Since the heating load requires at most 500,000 lb/hr of steam, a single boiler producing this flow of steam at turbine inlet conditions can meet the full heat demand as well as the full electricity demand. Water that is merely softened is adequate for boiler feed at the relatively low temperature and pressure of the boiler.

Option 3, Condensing Generation

Option 3 includes a 20 megawatt condensing turbine generator accepting 1,450 psia, 1000^{o}F steam and discharging steam 9 percent wet at 1.23 psia and 109^{o}F. To generate 20 megawatts, the turbine needs a steam flow of 150,000 lb/hr. Therefore, a high pressure boiler to serve the turbine generators would be sized at 150,000 lb/hr. It also includes a pair of boiler feed pumps and a demineralizer to supply feedwater. The condensing turbine requires heat rejection equipment; a vacuum surface condenser, a cooling tower, and a condensate storage tank are provided. To satisfy the heating steam demand, an entirely separate steam circuit is provided, with a 500,000 lb/hr low pressure boiler, a pair of pumps, and water softener.

Option 4, Condensing-Extraction Turbine Generation

Option 4 includes a condensing-extraction turbine generator which can produce 20 megawatts either with pure cogeneration flow or with pure condensing flow, or with any combination of the two types of flow in between. Actually

the turbine can generate up to 30 megawatts of mechanical power at some combinations of the two types of flow. To take advantage of this feature, an oversized electric generator has been specified, so that 30 megawatts of electricity can be generated under such turbine flow conditions. The turbine requires 280,000 lb/hr of steam flow to produce 20 megawatts by pure cogeneration. This is also the maximum flow the turbine can accept in any combination of cogenerating and condensing flow. Consequently, a high pressure boiler with its feedwater pumps and demineralizer are sized to 280,000 lb/hr of flow. To meet a 500,000 lb/hr heating steam demand, an extra 220,000 lb/hr flow is provided by a low pressure boiler with its pumps and softener. The turbine requires the same heat rejection equipment as a 20 megawatt condensing turbine.

Option 4A, Condensing-Extraction Generation with Lower Efficiency Boilers

Option 4A is similar to Option 4, except that the boilers do not have air preheaters. The boilers then operate with 80 percent overall efficiency instead of with 87 percent efficiency when oil is the fuel.

Option 4B, Condensing-Extraction Generation with Two Half-Size Plants

Option 4B is similar to Option 4, except that the loads for the turbine-generators, boilers, and condensers are met with two half-size components. Thus, two 10 megawatt condensing-extraction turbine-generators are provided, etc.

Option 4C, Condensing-Extraction Generation with Two Quarter-Size Plants

Option 4C is similar to Option 4B, except that the sizes for all components are cut in half.

EQUIPMENT FEATURES

Turbine-Generator Units

The turbine-generator units for the first seven configurations are commercially available industrial steam turbines described in the 1976 equipment

handbook of a major U.S. supplier (General Electric). The inlet pressure and temperature conditions for seven of the eight configurations are at the highest levels available for units in the sizes considered. The condensing-extraction turbines are of the automatic-extraction type that can be controlled with two flow valves, one for the inlet and one at the extraction port.

Boilers

The boilers specified are commercially available. Steam temperatures up to $1000^{\circ}F$ can be obtained without undue cost. Above $1000^{\circ}F$, however, boiler designs must include expensive specialty alloys. Consequently, $1000^{\circ}F$ steam is recommended for new high performance power generation equipment. The boilers are assumed to burn fuel oil as the primary fuel and natural gas as an alternate fuel.

Section 6

ECONOMICS

This section addresses the total costs for on-base electric power generation. First, operating and maintenance costs other than for energy are examined. These are combined with the energy use costs from Section 4 to indicate the economics of using existing on-base power generation facilities. Then capital costs are presented for the new oil-fired facilities described in Section 5. These are combined with energy and other operating costs in a life-cycle present value analysis that will show whether it is advantageous to install new oil-fired facilities to generate on-base electric power. Finally, various comparisons of life cycle costs will be presented.

OPERATING AND MAINTENANCE

Some information on the costs of labor, materials, contracts, and overhead for operating and maintenance can be obtained from the Utility Cost Analysis Reports for existing facilities. Since Philadelphia Naval Shipyard and Norfolk Navy Public Works Center are both oil-burning facilities, it is convenient to draw inferences from the data for these two bases:

	Philadelphia	Norfolk
Plant Age, Years	35	35
Average Fuel Use, 10^6 Btu/hr	280	480
Report Fiscal Year	1976	1977
Months in Fiscal Year	12	15
Fuel Consumed, 10^{12} Btu	3.0	5.1
Steam Generation O&M, 10^6 \$	1.2	3.0
Electricity Generated, 10^6 kWh	64	36
Electricity Generation O&M, 10^6 \$	.5	.2
Steam O&M/Fuel Consumed, \$/10^6 Btu	.40	.59
Power O&M/Power Produced, Mills/kWh	7.8	5.6

For comparing diferent ways to use existing facilities, operating and maintenance costs are most conveniently related to fuel use and power generated. For this purpose, the following values will be used:

Steam O&M/Fuel Consumed	.5 $\$/10^6$ Btu
Power O&M/Power Produced	6.7 mills/kWh

For comparing life cycle costs of new facilities, it would be more convenient to relate annual operating and maintenance costs to the replacement capital cost. The two bases above show the results as follows:

	Philadelphia	Norfolk
Steam Capacity 10^6 Btu/hr	600	900
Electricity Generated	Yes	Yes
Plant Replacement Cost, 10^6 \$	20	30
Total 12 Month O&M, 10^6 \$	1.7	2.6
(Annual O&M/Replacement)	8.5%	8.7%

An operating and maintenance annual charge of 9 percent of capital costs will be assumed in present value studies below.

EXISTING FACILITY COMPARISONS

In Section 4, energy cost comparisons suggested that it is attractive to generate electric power in existing oil-fired installations. Here, it is useful to confirm this with operating and maintenance costs included. For this purpose, Case 2 and Case 7 for Philadelphia operations will be compared as shown in Table 6-1 on the following page.

The comparison has shown that \$280,000/yr can be saved by generating an optimum amount of power at Philadelphia, compared to purchasing all power.

Table 6-1

ANNUAL COSTS OF ENERGY AT PHILADELPHIA

Case	2	7
Generation Strategy	All Power Purchased	Optimum Generation
Fuel Used, 10^{12} Btu	2.48	2.87
Electricity Generated, 10^{6} kWh	0.0	56
COSTS, MILLIONS OF DOLLARS		
Steam O&M	1.24	1.43
Electricity O&M	—	.38
Total O&M	1.24	1.81
Purchased Fuel and Electricity	11.44	10.59
Total O&M Plus Purchased Energy	12.68	12.40

CAPITAL COSTS

In Section 4, energy and cost calculations suggest that on-base power generation is advantageous for existing facilities. This conclusion has just been reconfirmed with operating and maintenance costs included in addition to energy costs. In Section 4 and Section 5, the condensing-extracting turbine generator unit was shown to be the most versatile power generation device for Navy bases, since it combines the capability for cogeneration and for peak shaving condensing generation. The obvious question is whether life cycle cost comparisons favor the purchase of new units of this type for use in oil-fired facilities. Consequently, of greatest interest here is a capital cost comparison between Option 1, a low pressure boiler facility with no on-base power generation, and Option 4, a high pressure system with a condensing-extraction turbine generator unit. The configurations of these options were described in Section 5 and in Appendix E. The results of the comparison are given in Table 6-2.

Table 6-2

CAPITAL COST COMPARISONS, PLANTS WITH AND WITHOUT POWER GENERATION CAPABILITY
(Costs in Thousands of Dollars)

Facility Configuration Option	1	4
Power Generation	No	Yes
Boiler Module	—	5,260
Turbine Module	2,850	6,170
Switch Station	—	850
Heat Rejection	—	380
Water Treatment	80	1,290
Total Field Costs	2,930	13,950
Engineering Services	310	1,570
Total Construction Costs	3,240	15,520
Startup Costs	360	1,680
Total Capital Costs	3,600	17,200

In Table 6-2, the field costs are divided into five modules:

- The boiler module, which contains the boiler, boiler pumps, and half the bulk piping, electrical and civil-structural costs for the facility
- The turbine module, which contains the turbine-generator unit, and the remaining half of the bulk costs
- The switching station, needed to connect power generated by the new plant with the base power distribution system
- The heat rejection module, which includes a vacuum-condenser, cooling tower, and condensate storage tank
- The water treatment module, which may consist of an inexpensive water softener, or a more expensive demineralizer

Two additional entries in Table 6-2 are:

- Engineering services, which include charges for design, procurement, and construction management
- Startup costs, which will be encountered by the owner and which include operating personnel training, spare parts inventory, plant startup costs, and owner management and reporting costs

One-sixth of each cost entry in Table 6-2 is a contingency allowance for small cost items that cannot be identified without a complete detailed design.

The comparison in Table 6-2 shows that an incremental cost of $13,600,000 is required to provide 20 megawatts of power generation capability along with generation of 500 x 10^6 Btu/hr of steam. The capital cost to provide low pressure steam only (Option 1) is $7,200 per 10^6 Btu/hr of heat load capacity. The incremental capital cost to provide electric power as well (Option 4 minus Option 1) is $680 per kilowatt of capacity.

Details of capital costs are given in Appendix F for each of the eight configuration options described in Section 5. In Table 6-3, certain comparisons of the total costs are noted. A comparison between Options 4B and 4C reveals a cost-capacity exponent of .82.

TOTAL LIFE CYCLE COSTS

Total present value costs for Options 1 and 4 are shown in Tables 6-4 and 6-5. The cost analysis methodology is provided by Reference 1. Differential inflation factors used are those dictated by Reference 2 and advised by Reference 3.

Comparisons of the total life cycle costs for Options 1 and 4 suggest that there is no incentive to install new facilities for generating electricity on a base, if oil is to be the fuel. The choice to include power generation facilities leads to a savings investment ratio of .003. The ratio must equal 1 to break even.

Table 6-3

COMPARISON OF CAPITAL COSTS OF FACILITY OPTIONS

Option	Description	Relative Total Cost
4	One 20 MW Condensing-Extraction Unit, High Inlet T,P	1.0
2	One 20 MW Noncondensing Unit, High Inlet T,P	.89
2A	One 20 MW Noncondensing Unit, Low Inlet T,P	.81
3	One 20 MW Condensing Unit, High Inlet T,P	.84
4A	Same as 4, Except No Air Preheater	.95
4B	Same as 4, Except Two Half-Size Plants	1.13
4C	Same as 4, Except Two Quarter-Size Plants	.64

ADDITONAL LIFE CYCLE COST COMPARISONS

The total life cycle costs for all eight configuration options are given in Appendix F. The following comparisons are worth noting:

- Pure Cogeneration is most favored. Option 2 is the least cost power generation option considered. It is almost economically attractive in a new facility.
- Base loaded condensing generation is unattractive. Option 3 is the worst option considered.
- High T,P inlet conditions are favored. Option 2 costs less than Option 2A.
- High boiler efficiency is favored. Option 4 costs less than Option 4A.

Table 6-4

PRESENT VALUES FOR OPTION 1
NO ON-BASE POWER GENERATION, 500 X 10^6 BTU/HR HEAT LOAD

Line Number	Cost Element	Differential Inflation Rate	Project Year	Amount, Thousands of Dollars		Discount Factor	Discounted Costs Thousand of Dollars
				One-Time	Recurring		
(1)	First-Year Construction	0	3	1,200		.788	946
(2)	Second-Year Construction	0	4	2,400		.717	1,721
(3)	Total Investment			3,600			2,666
(4)	Fuel Oil	+8	5-32		6,770	20.339	137,695
(5)	Electricity	+6	5-32		7,830	15.029	117,677
(6)	Operating and Maintenance Labor and Materials	0	5-32		324	6.666	2,160
(7)	Total Operating Costs				14,924		257,532
(8)	Total Project Costs						260,198

(9) Equivalent Energy (with purchased electricity at 11,600 Btu/kWh), 10^9 Btu: 145,000

(10) Discounted Dollars per 10^6 Btu: 1.79

Table 6-5

PRESENT VALUES FOR OPTION 4
20 MW CONDENSING EXTRACTION TURBINE, 500 X 10^6 BTU/HR HEAT LOAD

Line Number	Cost Element	Differential Inflation Rate	Project Year	Amount, Thousands of Dollars		Discount Factor	Discounted Costs Thousand of Dollars
				One-Time	Recurring		
(1)	First-Year Construction	0	3	5,700		.788	4,492
(2)	Second-Year Construction	0	4	11,500		.717	8,246
(3)	Total Investment			17,200			12,737
(4)	Fuel Oil	+8	5-32		9,518	20.339	193,587
(5)	Electricity	+6	5-32		3,463	15.029	52,045
(6)	Operating and Maintenance Labor and Materials	0	5-32		1,548	6.666	11,867
(7)	Total Operating Costs					14,529	257,499
(8)	Total Project Costs						270,236
(9)	Equivalent Energy (with purchased electricity at 11,600 Btu/kWh), 10^9 Btu:						119,900
(10)	Discounted Dollars per 10^6 Btu:				2.18		

Sensitivity to Fuel and Electricity Prices

The life cycle costs presented depend on the electricity and fuel oil prices assumed. Fuel oil was assumed to cost $\$3.00/10^6$ Btu. Electricity costs were assumed to be as in Figure 4-9, with a continuous purchase price approximately 25 mills/kWh. The effects of changes in the prices on the attractiveness of Options 4 and Option 2 are as follows:

- Option 4, cogeneration plus peak shaving condensing-generation, would break even if the fuel price dropped 18.0 percent to $\$2.44/10^6$ Btu, or if the electricity cost rose 15.3 percent to 28.8 mills/kWh.
- Option 2, pure cogeneration, would break even if the fuel cost dropped 5.5 percent to $\$2.83/10^6$ Btu, or if the electricity cost rose 3.5 percent to 25.9 mills/kWh.

Replacement Life Cycle Costs

Consider a newly purchased standby turbine that can be used either continuously or occasionally. The present value of the replacement cost after the turbine has exhausted its useful life is indicated by the following:

Item	Relative Present Value
Newly purchased standby turbine	1.0
Replacement after 28 years if used continuously	.073
Replacement after 84 years if used occasionally	.0004

There is a slight capital cost advantage to using a standby turbine occasionally rather than continuously. However, Tables 6-4 and 6-5 show that energy costs have much larger present values than do capital costs. Accordingly, the decision to use turbines occasionally rather than continuously will be dictated mainly by operating cost comparisons.

Reliability and Operability

System reliability and operability depend on system complexity. Costs to achieve good reliability and operability are assumed proportional to capital

costs. The simplest system will be a low pressure boiler system without power generation capability. However, condensing-extraction turbines are common at naval installations, and their complexity is manageable.

Ranking of Systems

The most versatile facility for a naval installation would be Option 4B, involving a pair of 10 megawatt condensing-extraction turbines. This system allows good response and efficiency when demands are low. It provides partial capability if a component fails in one-half of the system. The condensing-generation capability assures genuine readiness in case of failure in the local power grid. This option has the highest capital costs.

The lowest cost power generation system would involve a noncondensing turbine capable of cogeneration only. This system should have the highest inlet temperatures and pressures practical (Option 2).

Since no new electricity generation facilities look attractive in oil-fired systems, the lowest cost option is Option 1, with no provision for on-base power generation.

Section 7

RECOMMENDATIONS

This section presents the recommendations for the use of existing electricity generating facilities, those facilities at the Philadelphia and Charleston Naval Shipyards, and for new oil-fired electricity generation facilities.

GENERAL RECOMMENDATIONS ON EXISTING FACILITIES

Adopt a Cogeneration Strategy

Bases with operable power generation facilities should consider adopting the following power generation strategy, which will be attractive in terms of energy use and cost savings:

- Bases should generate as much power in the cogeneration mode as the heat load steam flow and the electric load will allow.
- Bases should generate in the condensing mode only for peak shaving, to keep the peak purchased power below a predetermined optimum limit.
- The optimum limit for a given year should be worked out by a simulation using current fuel and electricity cost schedules, and a reasonable projection of electricity and heat loads over the future 12 months.

Monitor Heating Steam Flows from Turbines

If they are not already doing so, bases producing heating steam from turbines should measure and record these flows so that due credit for cogeneration can be computed.

Change UCAR Recording Procedures

To permit the costs of generating electricity by cogeneration to be fairly reflected, the following changes in preparing the Utilities Cost Analysis Reports should be implemented:

- The cost of steam transferred to the electric generation system (Line 26, Column 6) should be for condensing-generation steam only.

- Energy costs for cogeneration should be entered by attributing part of the fuel used in the boiler to electricity generation. Thus, there should be nonzero entries under electricity (Column 6) for Fuel Btu Used (Line 15) and Fuel Costs (Line 18). The fuel quantity and cost for steam generation (Column 5) should be the difference between the total fuel and the fuel assigned to electricity generation (Column 6).

- The method for computing the fuel use in cogeneration is as follows: let X_i be the total pounds of steam that have flowed from turbine port i during the reporting period. Let R_i be the number of pounds of steam from port i needed to make one kilowatt hour of power. The value of R_i can be determined by study of the turbine performance for flow through port i. For each kilowatt hour of power generated, the amount of fuel consumed will be 4,000 Btu (assuming boiler efficiency of 85 percent). Then the fuel used to make power by steam exiting through port i is:

  $$\text{Fuel}_i \text{ (Btu)} = 4000\ X_i/R_i$$

  The total fuel is the sum for all the ports giving cogeneration heating steam.

RECOMMENDATIONS FOR PHILADELPHIA NAVAL SHIPYARD

Philadelphia should:

- Consider the recommended cogeneration strategy.

- Complete promptly the reactivation of their water demineralizer.

- Commission a detailed study of their recent load histories to arrive at the proper peak purchased power limit. This

study should be completed by the next summer air conditioning season. Prior to the completion of such a study, 14.2 megawatts may be used as the peak power purchased during the months of October through May.

- Use the following values of the R_i in computing electricity generation fuels:
  - For 200 psig steam from Turbine Number 4 (noncondensing-extraction turbine), use $R_i = R_1 = 28$ lb steam/kilowatt-hour.
  - For 60 psig steam from Turbine Number 4, use $R_i = R_2 = 18.0$ lb steam/kilowatt-hour.
  - For 60 psig steam from Turbines 5 and 6 (condensing-extraction turbine), use $R_i = R_3 = 24$ lb steam/kilowatt-hour.

RECOMMENDATIONS FOR CHARLESTON NAVAL SHIPYARD

No specific recommendations are made for Charleston Naval Shipyard. They may choose to reevaluate the tradeoff between energy cost savings and extra operation and maintenance costs for using the turbine continuously for cogeneration.

RECOMMENDATIONS ON NEW OIL-FIRED EQUIPMENT

Extra funds should not be spent to include on-base electric power generation facilities at naval bases, if fuel-oil is to be the fuel.

The most versatile system for generation of 20 megawatts of power would include two 10-megawatt condensing-extraction turbines.

Section 8

REFERENCES

1. "Economic Analysis Handbook," P-442, Naval Facilities Engineering Command, 1975.

2. Draft "Energy Escalation Rates for Short-Term and Life Cycle Listing."

3. "Assessment of Availability and Price of Fossil Fuels for Utility Purposes Through 1985," Hoffman-Muntner Corporation, June 1975.

4. SECNAVINST 4860.44A, "Commercial or Industrial Activities Program," 27 October 1971.

Appendix A

SUMMARY OF ENERGY USE AND COST COMPARISONS FOR CONFIGURATION OPTIONS

Appendix A presents a table that summarizes energy and costs of fuel and electricity purchases for nominal configuration and use options.

Table A-1

ENERGY AND COSTS OF FUEL AND ELECTRICITY PURCHASES FOR NOMINAL CONFIGURATION AND USE OPTIONS

Option	Description	Equivalent Energy (10^{12} Btu's)			Cost (Millions of Dollars)		
		Fuel	Electricity	Total	Fuel	Electricity	Total
1	No On-Base Generation	2.36	2.92	5.28	6.77	7.83	14.60
2	High Pressure Cogeneration	2.84	1.57	4.41	8.15	4.93	13.08
2A	Low-Pressure Cogeneration	2.68	2.03	4.71	7.68	6.09	13.77
3	Base Load Condensing Generation	4.48	.89	5.37	12.86	3.32	16.18
3A	Peak Shaving Condensing Generation	2.80	2.50	5.30	8.02	5.81	13.83
4	Condensing-Extraction Generation, Boiler Efficiency 87%	3.32	1.25	4.57	9.52	3.46	12.98
4A	Condensing-Extraction Generation, Boiler Efficency 80%	3.61	1.25	4.85	10.35	3.46	13.81

Appendix B

POWER GENERATION OPERATIONS AT PHILADELPHIA NAVAL SHIPYARD

The Philadelphia Naval Shipyard occupies approximately three square miles on the shore of the Delaware River, within the city limits of Philadelphia, Pennsylvania. The base is used as a shipyard for large naval vessels. Heating loads served by the steam plants include building space heating, some absorption air conditioners, industrial shops, and ships berthed in the piers or drydocks. All but a small fraction of the steam used on the base is generated in the utility center at Building 23. This center includes five oil-fired boilers with a total capacity of 750,000 lb/hr of steam. At one time these boilers fired coal, but coal handling equipment has been removed, and a parking lot covers the previous coal storage site.

One of the boilers in Building 23 makes 900 psig, 760^{o}F steam. This can be fed to a noncondensing turbine, or throttled down to the 400 psig, 720^{o}F condition of the steam generated by the other four boilers. The 400 psig steam can be fed to condensing extraction turbines, or it can be throttled and desuperheated to saturated 200 psig steam conditions. Ships, major shops, and some distant buildings need 200 psig steam service. A second network requires 60 psig steam service. The 60 psig steam demand can be satisfied either by extraction from one of the turbines or by pressure let-down from the 200 psig headers. About half of the steam demand each year is for 200 psig steam and half is for 60 psig steam. Some of the 200 psig steam flow can be supplied by extraction from the noncondensing turbine, but when the demand exceeds about 80,000 lb/hr, the balance must be made by desuperheating 720^{o}F steam. Currently, condensate is used to desuperheat, since the water demineralizer at the base has not yet been reactivated. Only 30 percent of the heating steam returns as condensate.

Building 23 contains four operational turbine-generator units which can generate a total of 20 megawatts. Turbine Number 4 is a 4-megawatt non-condensing turbine producing 200 psig steam by extraction and 60 psig steam by exhaust. Turbines Number 5 and 6 are 7-megawatt condensing turbines producing 60 psig steam by extraction, and an exhaust at a vacuum of 28 inches of mercury. Turbine Number 1 is a 2-megawatt condensing turbine fed with 200 psig steam.

Current practice at Philadelphia is to generate 40 percent of the electric load continuously all year round. The operators are concerned about production of enough condensate to meet the modest demand from ships and the larger demand for desuperheating steam in the winter.

Ten percent of the steam raised in the boilers is used for boiler feedwater heating and four percent is used to drive fans and boiler feedwater pumps.

Electricity charges at Philadelphia follow the curves in Figure 4-9, except that the ratio in the abscissa is (monthly average MW/billing demand MW). The billing demand for each of the four summer months of June, July, August, and September will be the peak demand for that month. For each of the following eight "winter" months, the billing demand will be either the peak demand for that month, or eighty percent of the highest demand during the previous summer, whichever is greatest.

Appendix C

SIMULATION FOR PHILADELPHIA ENERGY AND COST SAVINGS

A simple simulation computer program was constructed to carry out the energy use and cost analyses for Philadelphia Naval Shipyard. This simulator has been named PHILAGEN.

SIMULATOR DESCRIPTION

The following features and numerical settings have been used in the simulation calculations:

1. The equipment complement at Philadelphia has been approximated by a single 20 megawatt condensing-extraction turbine. This simplification is quite reasonable, and leads to very little calculation error.

2. A single extraction condition of 100 psig steam approximates the two condition mix of 200 psig and 60 psig steam.

3. Steam that bypasses the turbine can be desuperheated with condensate, or by makeup water as an alternate option. For over 30,000 lb/hr heating steam flow, half the additional steam required is assumed to bypass the turbine. This is in approximate agreement with Philadelphia operation.

4. The simulator provides 10 percent of the steam for heating boiler feedwater and 4 percent for operating pumps and fans, as at Philadelphia.

5. All days of a given month are assumed to have the same heat and electric load profiles. For each day of a given month, the following profiles are assumed, which approximate Philadelphia Naval Shipyard load data:

   - The heat load is constant at the monthly average value.

   - The electric load during the night time is 14 percent below the monthly average.

- The duration of the night time is 14.4 hours.

- The duration of the day time is 9.6 hours.

- The monthly peak electric load includes a zero width peak above the day time load.

6. The average heating load and the average and peak electric load used for each of the 12 months of the year are shown in Table C-1. They were loads actually occurring in Philadelphia in Fiscal Year 1976.

7. Both the recommended Bechtel strategy and the current Philadelphia generation strategy are available as strategy options.

8. The fuel and electricity prices are those used in the study of the four nominal options in Section 4.

Table C-1

MONTHLY STEAM AND ELECTRICITY LOAD DATA

Month	Average Steam Heating Load, 10^6 Btu/hr	Peak Electric Load, Megawatts	Average Electric Load, Megawatts
July	145	32.1	18.8
August	148	29.9	19.3
September	151	30.3	18.6
October	150	26.1	15.4
November	215	26.1	14.7
December	240	25.1	12.5
January	512	27.2	22.3
February	416	27.2	18.2
March	328	27.8	16.5
April	271	26.7	16.6
May	173	26.9	15.4
June	143	28.3	16.2

DETAILS OF RESULTS

The energy and costs of fuel and electricity purchases for the seven cases are shown in Table C-2. The purchased fuel and electricity energy and costs calculated for Case 1 are within 5 percent of the actual values on Philadelphia Naval Shipyard's Fiscal Year 1976 Utility Cost Analysis Report.

SENSITIVITY OF RESULTS

The cost of total energy purchases is quite sensitive to the peak purchased power setting chosen. In the simulation experiment, Bechtel searched for the optimum setting. The points explored are shown in Figure C-1. The figure shows that neighboring points can differ in annual costs by as much as $20,000. Because the results can be sensitive to the setting judged in advance to be optimum, there is a financial incentive to repeat the calculation periodically. Also, there appears to be an incentive to rerun the calculation in the near future with a more detailed definition of the load profiles for recent months, and to develop methods of analysis for predicting future loads.

POSSIBLE SIMULATOR MODIFICATIONS AND ENHANCEMENTS

The simulation computer program PHILAGEN can be refined at minimal cost to accommodate more detailed data, revised conditions, and systems at other shipyards. Some of the simple modifications include the following:

1. Revising any numerical values cited above under "Simulator Description"

2. Allowing more than one condition of product steam

3. Allowing a more complex turbine performance envelope than that for a single condensing-extraction turbine

4. Accommodating a more detailed definition of the electric load frequency over a given month

Table C-2

DETAILS OF PHILADELPHIA FUEL AND ELECTRICITY PURCHASES UNDER ALTERNATIVE GENERATION STRATEGIES

Case No.		Peak Purchased MW	Equivalent Energy (10^{12} Btu's)			Cost (Millions of Dollars)		
			Fuel	Elec-tricity	Total	Fuel	Elec-tricity	Total
1	Current Philadelphia Strategy (Generate 40% of lead)	19.1	3.05	1.08	4.12	8.74	2.63	11.37
2	Buy All Electricity, Generate None	32.1	2.48	1.73	4.21	7.11	4.33	11.44
3	Cogenerate Only, No Condensing Generation	28.5	2.67	1.21	3.88	7.66	3.34	11.00
4	Bechtel Strategy, No Demineralizer, Maximum Possible Shave (20 MW Maximum)	12.1	3.07	.98	4.05	8.79	2.07	10.86
5	Bechtel Strategy, No Demineralizer, Optimum Shave (18 MW Maximum)	14.1	2.95	1.03	3.98	8.47	2.29	10.76
6	Bechtel Strategy, with Demineralizer, Maximum Possible Shave (20 MW Maximum)	12.23	2.99	1.01	4.00	8.58	2.13	10.71
7	Bechtel Strategy, with Demineralizer, Optimum Shave (17.85 MW Maximum)	14.25	2.87	1.08	3.95	8.23	2.36	10.59

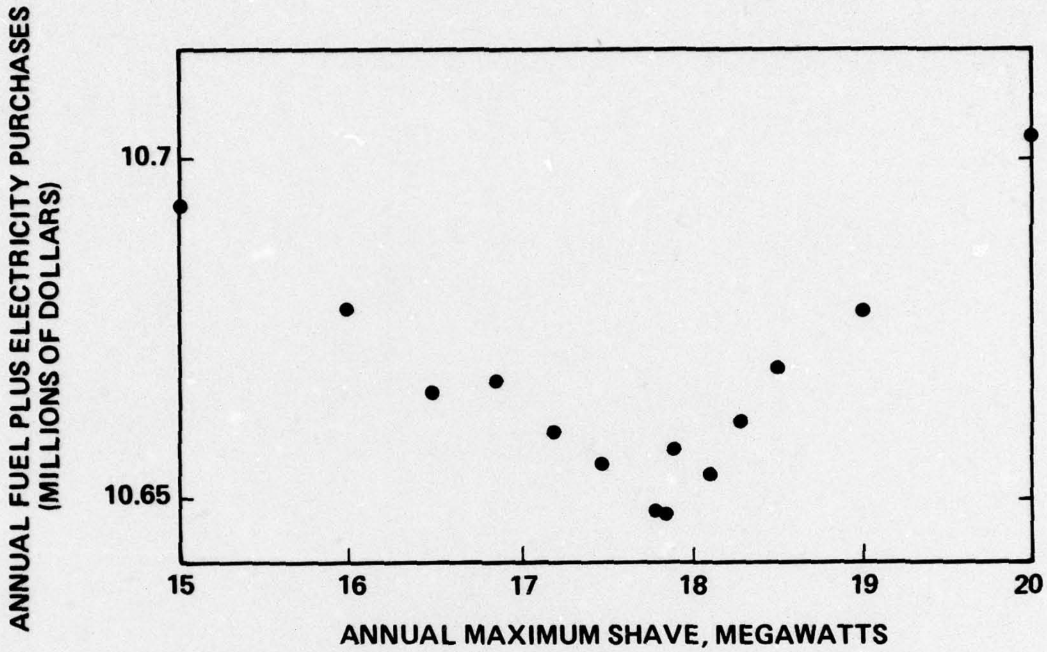


Figure C-1. Cost Sensitivity to Maximum Shave

Appendix D

POWER GENERATION OPERATIONS AT CHARLESTON NAVAL SHIPYARD

The Charleston Naval Shipyard is located about seven miles north of the City of Charleston, South Carolina, near the Atlantic Coast. The shipyard covers an area 3,000 feet wide and about five miles long, following the south bank of the Cooper River.

The base is used as a shipyard for large naval, oceangoing vessels. There are 18 berthing piers, and five drydock facilities. Heating loads served by the steam plants include berthed ships and buildings. The piers and drydocks are located in a three-mile stretch along the river. Buildings are located in all areas of the site, and there are few open spaces. The buildings are used for administration, services, recreation, schools, shops and warehouses. There are 116 buildings serving as naval quarters.

The main steam plant includes five coal-fired boilers, which have a total capacity of 291 million Btu/hr. The main steam plant serves the piers, drydocks, and some buildings. In addition to the main plant, there are 84 smaller oil-fired boilers which have a total capacity of 327 million Btu/hr. These boilers are in 30 different locations, and they serve individual buildings. The naval quarters are heated individually.

The boilers in the main plant produce steam at 425 psig, 625^{o}F. The steam is used to produce electrical power as well as to supply steam demands from ships and buildings. Steam at 425 psig, 625^{o}F, is supplied to the steam turbine-generator equipment, but ships and buildings are supplied with 165 psig, saturated steam from a depressuring and desuperheating station at the main plant. The steam turbine includes automatic extraction of 165 psig steam, which is also supplied to ships and buildings.

The steam turbine-generator at the main plant has 5,000 kW capacity. This unit was installed in 1943. A second steam turbine-generator, with 2,500 kW capacity is not being run because it needs repair. This unit was installed in 1940.

In 1976, the steam turbine-generator operated for 2,577 hours (load factor = 0.29). In 1976, the in-house generator produced 12,887 MWh of electrical energy, and 207,907 MWh of electrical energy were purchased. The in-house generator which is operated to reduce demands from the public utility, during periods of peak load supplied 5.8 percent of the base demand. This operation saves costs due to demand charge. In 1977, the electric purchases for the year averaged 24,077 kW, and the peak purchased power during the year was 35,986 kW, which occurred in the month of August.

Fuel consumption in the main plant averaged 116 million Btu/hr in 1977. During the month with heaviest use, the average consumption rate was 179 million Btu/hr.

Appendix E

SUMMARIZED NEW EQUIPMENT FOR CONFIGURATION OPTIONS

Appendix E is a table that summarizes new equipment and configuration options.

Option Number		1	2	2A	3	4
Turbine	Quantity	None	1	1	1	1
	Power, MW		20	20	20	20
	Type		Noncondensing	Noncondensing	Condensing	Condensing Extraction
High Pressure Boiler	Quantity	None	1	1	1	1
	10^3 lb/hr		320	500	150	280
	Pressure, psia		1,450	565	1,450	1,450
	Temperature ^oF		830	625	1,000	1,000
	With Air Preheater		Yes	Yes	Yes	Yes
Low Pressure Boiler	Quantity	1	1	None	1	1
	10^3 lb/hr	500	180		500	220
	Pressure, psia	100	100		100	100
	Temperature, ^oF	340	340		340	340
High Pressure BFW Pump	Quantity	None	2	2	2	2
	Horsepower		640	350	300	560
	Gallons/minute		640	1,000	300	560
Low Pressure BFW Pump	Quantity	2	2	None	2	2
	Horsepower	100	36		100	44
	Gallons/minute	1,000	360		1,000	440
Electric Switch Station	Quantity	None	1	1	1	1
	Power, MW		20	20	20	20
Condenser	Quantity				1	1
	Surface, ft^2	None	None	None	11,200	11,200
Cooling Tower	10^6 Btu/hr	None	None	None	140	140
Condensate Tank	Gallons	None	None	None	30,000	30,000
Water Demineralizer	Gallons/minute	None	640	None	300	560
Water Softener	Gallons/minute	1,000	360	1,000	1,000	440

Table E-1

SUMMARIZED NEW EQUIPMENT
FOR CONFIGURATION OPTIONS

4A	4B	4C
1	2	2
20	10	5
Condensing-Extraction	Condensing-Extraction	Condensing Extraction
1	2	2
280	140	70
1,450	1,450	1,450
1,000	1,000	1,000
No	Yes	Yes
1	2	2
220	110	55
100	100	100
340	340	340
2	4	4
560	280	140
560	280	140
2	4	4
44	22	11
440	220	110
1	1	1
20	20	10
1	2	2
11,200	5,600	2,800
140	140	70
30,000	30,000	15,000
560	560	280
440	440	220

Appendix F

SUMMARIZED INVESTMENT AND OPERATING COSTS FOR CONFIGURATION OPTIONS

Appendix F is a table that summarizes investment and operating costs for configuration options.

Option Number		1	2	2A	3	4
Option	Configuration					
Turbine	Quantity	None	1	1	1	1
	Power, MW		20	20	20	20
	Type		Noncondensing	Noncondensing	Condensing	Condensing-Extraction
Boiler Plant	Quantity	1	1	1	1	1
	Energy Rate	500×10^6 Btu/hr	500×10^6 Btu/hr	500×10^6 Btu/hr	650×10^6 Btu/hr	500×10^6 Btu/hr
	Pressure	100 psig	1,450 psig	525 psig	1,450 psig	1,450 psig
	Efficiency	87	87	87	87	87
1978 CAPITAL COSTS						
Turbine Module		—	4,050	3,970	4,050	5,260
Boiler Module		2,850	6,070	6,080	5,280	6,170
Electric Switch Station		—	850	850	850	850
Heat Rejection		—	—	—	380	380
Water Treatment		80	1,370	90	1,000	1,290
Total Direct Costs		2,930	12,340	10,990	11,560	13,950
Total Capital Costs*		3,600	15,300	13,900	14,400	17,200
1978 ANNUAL COSTS						
Fuel Oil		6,770	8,147	7,677	12,858	9,518
Electricity		7,830	4,934	6,092	3,320	3,463
Oprns. & Maint. Labor & Material		324	1,377	1,251	1,296	1,548
Total Annual Costs		14,924	14,458	15,020	17,474	14,529
1978 PRESENT VALUES						
First Year Construction		946	4,019	3,625	3,782	4,492
Second Year Construction		1,721	7,313	6,668	6,883	8,246
Fuel Oil		137,695	165,702	156,143	261,519	193,587
Electricity		117,677	74,153	91,557	49,896	52,045
Oprns. & Maint. Labor & Material		2,160	10,556	9,590	8,639	11,867
Total Life Cycle Present Value		260,198	261,743	267,582	330,720	270,236

* Total Capital Costs = 1.23 x Total Direct Costs

SUMMARIZED INVESTMENT AND OPERATING
COSTS FOR CONFIGURATION OPTIONS
(Thousands of Dollars)

4	4A	4B	4C
1	1	2	2
20	20	10	5
nsing-	Condensing-	Condensing-	Condensing-
ction	Extraction	Extraction	Extraction
1	1	2	2
x 10^6	500 x 10^6	250 x 10^6	125 x 10^6
/hr	Btu/hr	Btu/hr	Btu/hr
psig	1,450 psig	1,450 psig	1,450 psig
7	80	87	87
5,260	5,230	6,220	3,460
6,170	5,410	6,850	3,840
850	850	850	420
380	380	410	220
1,290	1,290	1,290	900
3,950	13,160	15,620	8,840
7,200	16,300	19,400	11,000
9,518	10,351	9,518	4,759
3,463	3,463	3,463	1,732
1,548	1,467	1,746	990
4,529	15,281	14,727	7,481
4,492	4,255	5,122	2,916
8,246	7,815	9,249	5,234
3,587	210,528	193,587	96,793
2,045	52,045	52,045	26,030
1,867	11,867	11,639	6,599
0,236	286,511	271,642	137,573